

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No.



**FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of
Major Electric Utilities, Licensees
and Others and Supplemental
Form 3-Q: Quarterly Financial Report**

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

SWEPCO

Year/Period of Report
End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

- a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.
- b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
- c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
- d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

- e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert

the List of Schedules, pages 2 and 3.

- V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.
- X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

- I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
- II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.
- g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

- a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power;
11. "project" means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

- a. "To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

- a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on
- FERC FORM NO. 1 (ED. 03-07)**

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent SWEPCO		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1 Riverside Plaza, Columbus, Ohio 43215-2373		
05 Name of Contact Person Jason M. Johnson		06 Title of Contact Person Accountant
07 Address of Contact Person (Street, City, State, Zip Code) AEP Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215-2373		
08 Telephone of Contact Person, Including Area Code (614) 716-1000	09 This Report is An Original / A Resubmission (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 11/05/2025
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Jeffrey W. Hoersdig	03 Signature Jeffrey W. Hoersdig	04 Date Signed (Mo, Da, Yr) 11/05/2025
02 Title Assistant Controller		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	
25	Unrecovered Plant and Regulatory Study Costs	230b	

26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	

60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig, Assistant Controller

212 East Sixth StreetTulsa, Oklahoma 74119

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of DelawareJune 29, 1912

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Public Utility engaged in generating, purchasing, transmitting, distributing and selling electric energy.Qualified to do business in the states of Arkansas, Louisiana, Oklahoma and Texas. The Company owns transmission facilities but provides no electric service at retail in Oklahoma.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) Yes

(2) No

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
American Electric Power Company, Inc., a registered holding company, owns 100% of the Respondent's outstanding shares of Common Stock.			

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Southwest Arkansas	Aid in Right of Way	100%	
2		Acquisition		
3	Dolet Hills Lignite Company	Lignite Mine Operator	100%	
4	Sabine Mining Company	Lignite Mine Operatore		1
5	Oxbow Lignite Company, LLC	Lignite Mine Reserves	50%	2
6	Mutual Energy SWEPCO, LLC	Energy Company	100%	
7	Footnote 1-			
8	Accounting guidance for Variable Interest			
9	Entities - Respondent contracts to			
10	Purchase 100% of the lignite mined			
11	Footnote 2-			
12	Ownership of the Oxbow Mining Company is held			
13	Jointly with Cleco Power Company LLC			

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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Footnote				

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FOOTNOTE DATA

(a) Concept: OfficerTitle

Schedule Page: 104 Line No.: 1 Column: a

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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	David M. Feinberg, Secretary and Vice President	Columbus, Ohio	false	false
2	Therace M. Risch, Vice President	Columbus, Ohio	false	false
3	Julia A. Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio	false	false
4	Phillip R. Ulrich, Vice President	Columbus, Ohio	false	false
5	Christian T. Beam, Vice President	Columbus, Ohio	false	false
6	Peggy I. Simmons, Vice President	Columbus, Ohio	false	false
7	D Brett. Mattison, President and Chief Operating Officer	Columbus, Ohio	false	false
8	Antonio P. Smyth, Vice President	Columbus, Ohio	false	false
9	Charles E. Zebula, Chief Financial Officer, Vice President	Columbus, Ohio	false	false
10	William J. Fehrman, Chair of the Board and Chief Executive Officer	Columbus, Ohio	false	false
11	Trevor I. Mihalik, Chief Financial Officer and Vice President	Columbus, Ohio	false	false
12	Benjamin G S. Fowke - Chair, Chief Executive Officer and Senior Advisor	Columbus, Ohio	false	false
13	The Respondent does not have an Executive Committee.			

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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Rate Schedule 119	ER19-159-000
2	Rate Schedule 125	ER18-2374-000
3	Rate Schedule 126	ER18-2349-000
4	Rate Schedule 127	ER18-1824-000
5	Rate Schedule 128	ER18-1774-000
6	Rate Schedule 129	ER19-171-000
7	SPP FERC Electric Tariff 6th Revision Vol. No. 1	ER07-1069
8	Addendum 4 to Attachment H, Parts 1 and 2	
9	SPP FERC Electric Tariff Vol. No. 1	ER18-195
10	Attachment H, Parts 1 and 2	

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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No (Checked by default - Not explicitly defined)
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2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20090526-5302	05/26/2009	ER09-1198-000	AEP SPP 2009 Trans FR Update	SPP OATT Att. H-4
2	20090831-5276	08/31/2009	ER09-1198-000	Errata of 2009 Update	SPP OATT Att. H-4
3	20100525-5109	05/25/2010	ER10-355-000	AEP SPP 2010 Trans FR Update	SPP OATT Att. H-4
4	20110928-5123	09/28/2011	ER11-4671-000	AEP SPP 2011 Trans FR Update	SPP OATT Att. H-4
5	20111221-5253	12/21/2011	ER11-1069-000	Errata of 2011 Update	SPP OATT Att. H-4
6	20120523-5024	05/23/2012	ER07-1069-000	AEP SPP 2012 Trans FR Update	SPP OATT Att. H-4
7	20130910-3004	05/24/2013	ER13-1606-000	AEP SPP 2013 Trans FR Update	SPP OATT Att. H-4
8	20141208-5379	12/08/2014	ER07-1069-000	AEP SPP 2014 Trans FR Update	SPP OATT Att. H-4
9	20150604-5186	05/14/2015	ER07-1069-000	AEP SPP 2015 Trans FR Update	SPP OATT Att. H-4
10	20160523-5233	05/23/2016	ER07-1069-000	AEP SPP 2016 Trans FR Update	SPP OATT Att. H-4
11	20160630-5407	06/30/2016	ER07-1069-000	Errata of 2016 Update	SPP OATT Att. H-4
12	20170525-5337	05/25/2017	ER07-1069-000	AEP SPP 2017 Trans FR Update	SPP OATT Att. H-4
13	20171031-5311	10/31/2017	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
14	20180525-5243	05/25/2018	ER18-195-000	AEP SPP 2018 Trans FR Update	SPP OATT Att. H-4
15	20181101-5217	11/01/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
16	20181213-5182	12/13/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
17	20190528-5199	05/28/2019	ER18-195-000	AEP SPP 2019 Trans FR Update	SPP OATT Att. H-4
18	20190723-5114	07/23/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4

19	20190724-5030	07/24/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
20	20190731-5132	07/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
21	20191031-5138	10/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
22	20200526-5243	05/26/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
23	02200609-5107	06/09/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
24	20201102-5246	11/02/2020	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
25	20210525-5227	05/25/2021	ER18-195-000	AEP SPP 2021 Trans FR Update	SPP OATT Att. H-4
26	20211101-5258	11/01/2021	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
27	20220525-5165	05/25/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
28	20220602-5172	06/02/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
29	20221101-5102	11/01/2022	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
30	20230525-5144	05/25/2023	ER18-195-000	AEP SPP 2023 Trans FR Update	SPP OATT Att. H-4
31	20231031-5363	10/31/2023	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
32	20240528-5345	05/28/2024	ER18-195-000	AEP SPP 2024 Trans FR Update	SPP OATT Att. H-4
33	20240614-5129	06/14/2024	ER18-195-000	AEP SPP 2024 Trans FR Update	SPP OATT Att. H-4
34	20241031-5377	10/31/2024	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

By Company-Community	Renewal Date/Auto Renewal	Consideration
Gilliam, Caddo Parish, LA	4/1/2034	None
Gilliam, Caddo Parish, LA	4/1/2024	None

None

None

None

None

Short-Term Debt and Commercial Paper
FERC Authority (Docket No. ES23-64-000) for Southwestern Electric Power Company

Long Term
SWEPCO Storm Recovery Funding LLC, Series 2024-A
\$336.7M
FERC Authority: Docket No. ES24-7-000
Issued: 12/10/2024
Maturity: 09/01/2041

None

None
None
None
Not Used
<p>III Benjamin G S Fowke, elected as Director, Chief Executive Officer and Chair of the Board effective on 02-26-2024 Daniel E Mueller, elected as Vice President-Tax effective on 01-27-2024 William C. Bradford, elected as Vice President - External Affairs effective on 03-11-2024 Noah K Hollis, elected as Assistant Treasurer effective on 03-30-2024 William J Fehrman elected as Chair, Chief Executive & Director effective on 08-01-2024 III Benjamin G S Fowke elected as Senior Advisor effective on 08-01-2024 Melissa A Gage, elected as Vice President - Regulatory & Finance Officer effective on 10-26-2024 Matthew D Fransen, elected as Vice President Officer effective on 12-01-2024 Matthew D Fransen, elected as Treasurer Officer effective on 12-01-2024 Julia A Sloat, resigned as Director, Chair of the Board, Chief Executive Officer effective on 02-25-2024 Daniel E Mueller, resigned as Assistant Vice President - Tax on 01-26-2024 James X Llende, resigned as Vice President-Tax on 01-25-2024 Renee V Hawkins, resigned as Assistant Treasurer effective on 05-03-2024 III Benjamin G S Fowke, resigned as Director effective on 08-26-2024 III Benjamin G S Fowke, resigned as Chair & Chief Executive effective on 07-31-2024 Therace M, Risch resigned as Director effective on 09-23-2024 Peggy I Simmons resigned as Director effective on 09-23-2024 Antonio P Smyth resigned as Director effective on 09-23-2024 Phillip R Ulrich resigned as Director effective on 09-23-2024 Christian T Beam, resigned as Director effective on 09-23-2024 Thomas P Brice, resigned as Vice President - Regulatory & Finance Officer effective on 12-03-2024 Julie A Sherwood, resigned as Vice President Officer effective on 11-30-2024 Julie A Sherwood, resigned as Treasurer Officer effective on 11-30-2024 Peggy I Simmons, resigned as Vice President Officer effective on 10-31-2024 III Benjamin G S Fowke, resigned as Senior Adviser effective on 10-22-2024</p>
Proprietary capital ratio exceeds 30%

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	12,196,404,806	11,137,333,923
3	Construction Work in Progress (107)	200	633,334,653	560,906,375
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,829,739,459	11,698,240,298
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	3,234,786,957	3,036,989,283
6	Net Utility Plant (Enter Total of line 4 less 5)		9,594,952,502	8,661,251,015
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,594,952,502	8,661,251,015
15	Utility Plant Adjustments (116)		(172,737,899)	(171,735,513)
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		90,802,812	87,516,842
19	(Less) Accum. Prov. for Depr. and Amort. (122)		64,682,168	63,743,826
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	13,152,390	12,189,280
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		1,025,469	1,025,469
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)		79,723,655	57,435,760
30	Long-Term Portion of Derivative Assets (175)			

31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		120,022,158	94,423,525
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,614,022	2,419,627
36	Special Deposits (132-134)		4,790,958	1,287,557
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		32,976,942	37,400,573
41	Other Accounts Receivable (143)		7,344,681	8,155,387
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,352	308
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		51,072,381	43,843,322
45	Fuel Stock (151)	227	83,256,579	110,249,718
46	Fuel Stock Expenses Undistributed (152)	227	3,216,405	3,582,634
47	Residuals (Elec) and Extracted Products (153)	227	424	
48	Plant Materials and Operating Supplies (154)	227	79,617,090	84,172,252
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	299,810	365,565
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	2,643	1,700
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		15,013,415	30,052,241
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		1,556,532	1,551,112
61	Accrued Utility Revenues (173)		42,037,720	42,982,873
62	Miscellaneous Current and Accrued Assets (174)		760,586	(9,143)
63	Derivative Instrument Assets (175)		18,110,561	11,598,372
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			

65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		341,667,397	377,653,482
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		19,904,686	21,983,823
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	972,925,250	1,329,555,443
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,504,742	5,173,575
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		4,300	4,300
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	109,722,562	115,766,894
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		3,548,603	4,148,378
82	Accumulated Deferred Income Taxes (190)	234	259,694,168	(9)412,885,884
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		1,367,304,311	1,889,518,297
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,251,208,468	10,851,110,806

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: FuelStock

Formula Rate uses 13 month average.

(b) Concept: PlantMaterialsAndOperatingSupplies

Formula Rate uses 13 month average. Production materials and supplies are identified by a query of the general ledger system.

(c) Concept: AccumulatedDeferredIncomeTaxes

Formula Rate uses 13 month average.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non Utility Items - 190.2	(6,486)	1
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	204,754,687	131,602,093
Accu Def Income Taxes Pension-OCI	1,306,878	(291,242)
Total	206,055,079	131,310,852

Line 18
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :

Balance at Beginning of Year	412,885,884
(Less) Amounts Debited to:	
(a) Account 410.1	(343,954,865)
(b) Account 410.2	—
(c) 1823/254/219/129/427	(16,552,256)
(Plus) Amounts Credited to:	
(a) Account 411.1	175,389,446
(b) Account 411.2	6,487
(c) 1823/254/219/129/427/421	31,919,472
Balance at End of Year	259,694,168

See Note 18 - Resubmission Disclosure - Income Taxes for additional information on the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities.

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	66,240	66,240
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	1,549,690,898	1,492,147,009
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		437
11	Retained Earnings (215, 215.1, 216)	118	2,304,406,183	2,234,651,756
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	48,169,474	46,704,257
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	2,319,609	(3,417,071)
16	Total Proprietary Capital (lines 2 through 15)		3,904,652,404	3,770,151,754
17	LONG-TERM DEBT			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	3,675,000,000	3,675,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		5,745,381	6,076,501
24	Total Long-Term Debt (lines 18 through 23)		3,669,254,619	3,668,923,499
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		152,304,944	140,930,229
27	Accumulated Provision for Property Insurance (228.1)		106,199,473	
28	Accumulated Provision for Injuries and Damages (228.2)		92,186	114,682
29	Accumulated Provision for Pensions and Benefits (228.3)		44,949,229	41,246,894

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		175,420,127	24,880,007
32	Long-Term Portion of Derivative Instrument Liabilities		11,652	1,230,719
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		183,128,831	148,020,016
35	Total Other Noncurrent Liabilities (lines 26 through 34)		662,106,442	356,422,547
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		264,346,196	198,055,606
39	Notes Payable to Associated Companies (233)		274,992,487	88,726,336
40	Accounts Payable to Associated Companies (234)		104,722,613	90,757,307
41	Customer Deposits (235)		75,386,015	72,470,328
42	Taxes Accrued (236)	262	17,976,873	27,290,089
43	Interest Accrued (237)		40,596,875	39,887,705
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		6,007,428	7,033,579
48	Miscellaneous Current and Accrued Liabilities (242)		180,988,963	221,106,896
49	Obligations Under Capital Leases-Current (243)		11,614,801	20,011,366
50	Derivative Instrument Liabilities (244)		2,276,747	15,609,127
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		11,652	1,230,719
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		978,897,346	779,717,620
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	74,952	186,614
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	63,334,609	63,662,592
60	Other Regulatory Liabilities (254)	278	438,998,746.00	617,443,904.00
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	44,742,107	46,703,381
63	Accum. Deferred Income Taxes-Other Property (282)		1,150,701,160	1,102,280,088

64	Accum. Deferred Income Taxes-Other (283)		338,446,083	445,618,808
65	Total Deferred Credits (lines 56 through 64)		2,036,297,657	2,275,895,387
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,251,208,468	10,851,110,807

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Formula Rate uses 13 month average.

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) t amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenue: the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenue amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate pro revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense ac
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, incl allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to th

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)
1	UTILITY OPERATING INCOME									
2	Operating Revenues (400)	300	1,919,137,231	2,034,978,853			1,919,137,231	2,034,978,853		
3	Operating Expenses									
4	Operation Expenses (401)	320	1,004,321,129	996,552,378			1,004,321,129	996,552,378		
5	Maintenance Expenses (402)	320	149,381,461	159,681,387			149,381,461	159,681,387		
6	Depreciation Expense (403)	336	345,310,030	293,761,539			345,310,030	293,761,539		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	3,971,829	2,162,759			3,971,829	2,162,759		

24	Accretion Expense (411.10)		4,861,903	4,316,391			4,861,903	4,316,391		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,607,472,541	1,623,316,347			1,607,472,541	1,623,316,347		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		311,664,690	411,662,506			311,664,690	411,662,506		
28	Other Income and Deductions									
29	Other Income									
30	Nonutility Operating Income									
31	Revenues From Merchandising, Jobbing and Contract Work (415)									
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)									
33	Revenues From Nonutility Operations (417)									
34	(Less) Expenses of Nonutility Operations (417.1)		372							
35	Nonoperating Rental Income (418)		301	318						
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,465,217	1,484,033						
37	Interest and Dividend Income (419)		14,040,547	17,923,242						
38	Allowance for Other Funds Used During Construction (419.1)		13,539,670	11,501,698						
39	Miscellaneous Nonoperating Income (421)		115,451,182	939,056						
40	Gain on Disposition of Property (421.1)		1,358,196	160,451						

74	(Less) Extraordinary Deductions (435)									
75	Net Extraordinary Items (Total of line 73 less line 74)									
76	Income Taxes-Federal and Other (409.3)	262								
77	Extraordinary Items After Taxes (line 75 less line 76)									
78	Net Income (Total of line 71 and 77)		321,219,644	220,288,486						

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: ProvisionForDeferredIncomeTaxesCreditOtherIncomeAndDeductions
See Note 19 - Resubmission Disclosure – Income Taxes for additional information on the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities.

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,234,651,756	2,190,847,304
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Adj to Retained Earnings			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		319,754,427	218,804,453
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	\$18 par value - 7,536,640 shares outstanding		(250,000,000)	(175,000,001)
30.2	Total Dividends Decl - Common Stk (438)			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(250,000,000)	(175,000,001)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,304,406,183	2,234,651,756

39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,304,406,183	2,234,651,756
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		46,704,257	45,220,224
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,465,217	1,484,033
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		48,169,474	46,704,257

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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STATEMENT OF CASH FLOWS

- Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
- Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
- Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	321,219,644	220,288,486
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	381,334,096	328,219,224
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	9,665,074	15,485,778
8	Deferred Income Taxes (Net)	(73,931,390)	57,388,039
9	Investment Tax Credit Adjustment (Net)	(111,663)	(247,752)
10	Net (Increase) Decrease in Receivables	(1,997,100)	20,425,210
11	Net (Increase) Decrease in Inventory	26,947,354	(48,305,188)
12	Net (Increase) Decrease in Allowances Inventory	65,756	2,360,301
13	Net Increase (Decrease) in Payables and Accrued Expenses	(3,611,248)	(20,111,160)
14	Net (Increase) Decrease in Other Regulatory Assets	265,082,891	112,009,842
15	Net Increase (Decrease) in Other Regulatory Liabilities	21,494,668	5,477,334
16	(Less) Allowance for Other Funds Used During Construction	13,539,670	11,501,698
17	(Less) Undistributed Earnings from Subsidiary Companies	1,465,217	1,484,033
18	Other (provide details in footnote):		
18.1	^(a) Other (provide details in footnote):	227,379,796	(3,648,586)
18.2	Mark-to-Market of Risk Management Contracts	(19,844,564)	19,076,334
18.3	Impairment of Long-Lived Assets		85,605,840
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,138,688,427	781,037,971
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(757,664,411)	(798,841,089)

27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		(3,033)
30	(Less) Allowance for Other Funds Used During Construction	(13,539,670)	(11,501,698)
31	Other (provide details in footnote):		
31.1	Acquired Assets	(401,081,651)	(849,735)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,145,206,392)	(788,192,159)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	6,193,724	1,436,933
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Insurance Receivable		382,369
53.2	Other (Provide details in footnote)	5,051,544	2,934,698
53.3	(Increase) Decrease in Other Special Deposits	22,179	(9,484)
53.4	Notes Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,133,938,945)	(783,447,643)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		350,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		

64.2	Long Term Issuances Costs	(373,300)	(3,215,762)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Capital Leaseback	1,008,174	812,495
67.2	Notes Payable to Associated Companies - Issued	186,266,151	
67.3	Capital Contributions from Parent	57,543,889	50,001,599
70	Cash Provided by Outside Sources (Total 61 thru 69)	244,444,914	397,598,331
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired		(221,930,659)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(250,000,000)	(175,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(5,555,086)	667,672
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(805,604)	(1,742,000)
88	Cash and Cash Equivalents at Beginning of Period	2,419,627	4,161,626
90	Cash and Cash Equivalents at End of Period	1,614,023	2,419,627

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Utility Plant, Net	\$ 23,431,494	\$ (38,501,686)
Property and Investments, Net	(1,845,521)	1,567,988
Margin Deposits	(3,525,581)	15,226,225
Prepayments	10,519,864	992,423
Accrued Utility Revenues, Net	945,153	6,013,818
Miscellaneous Current and Accr Assets	6,125,000	—
Unamortized Debt Expense	2,452,437	2,248,363
Other Deferred Debits, Net	2,384,035	(53,014,670)
Other Comprehensive Income, Net	(275,298)	187,375
Unamortized Discount/Premium on Long-Term Debt	331,120	323,479
Accumulated Provisions - Misc	255,123,963	12,597,321
Current and Accrued Liabilities, Net	(36,506,231)	21,198,913
Other Deferred Credits, Net	(11,936,075)	27,511,865
Total	\$ 247,224,360	\$ (3,648,586)

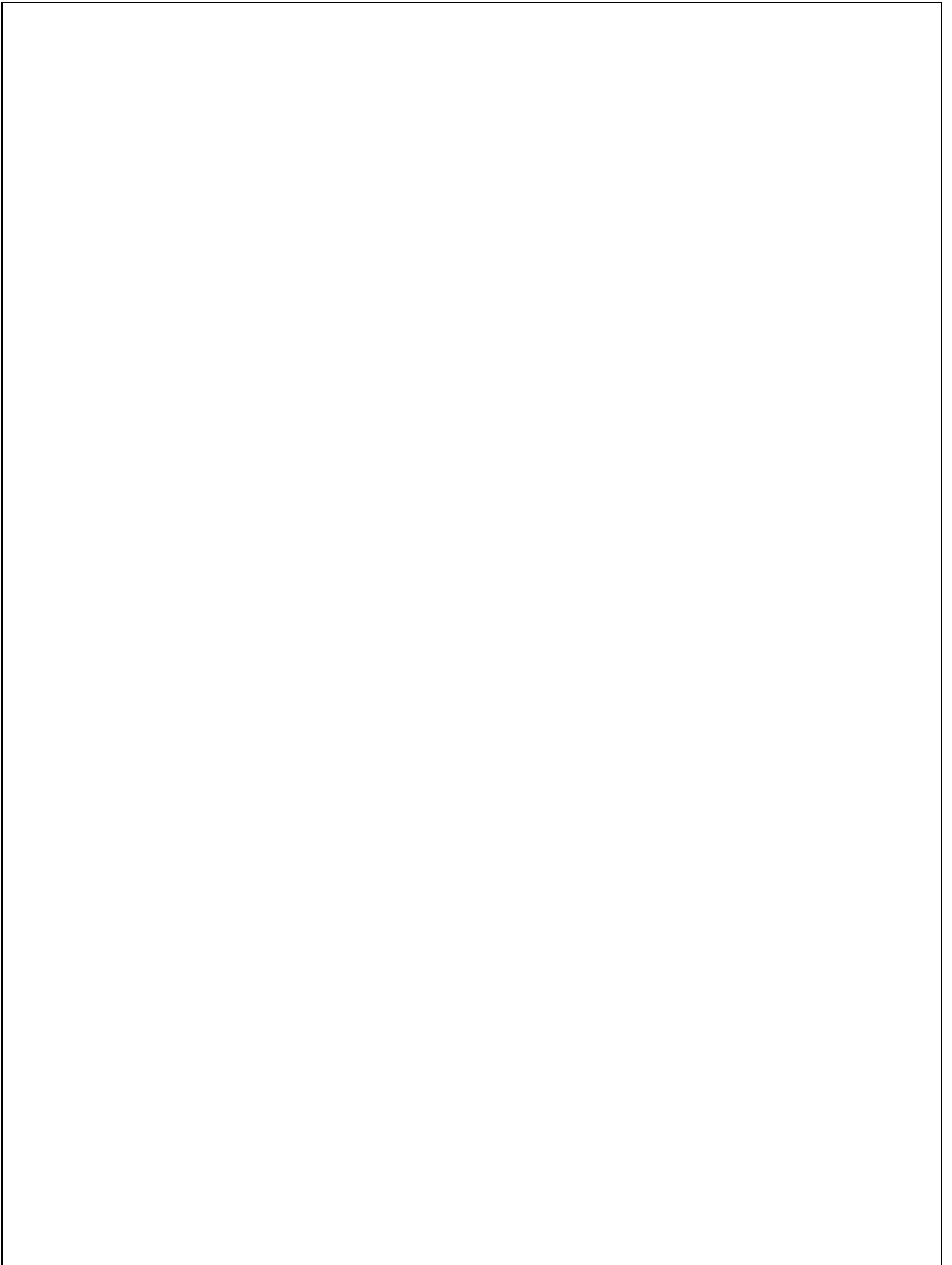
(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Stonewall Substation		724,297
Sales of Land	1,905,110	
Sales of Meters	10,850	29,417
Sales of Material	2,711,773	
Sales of Transformers	1,565,991	683,219
Total	\$ 6,193,724	\$ 1,436,933

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.



INDEX OF NOTES TO FINANCIAL STATEMENTS

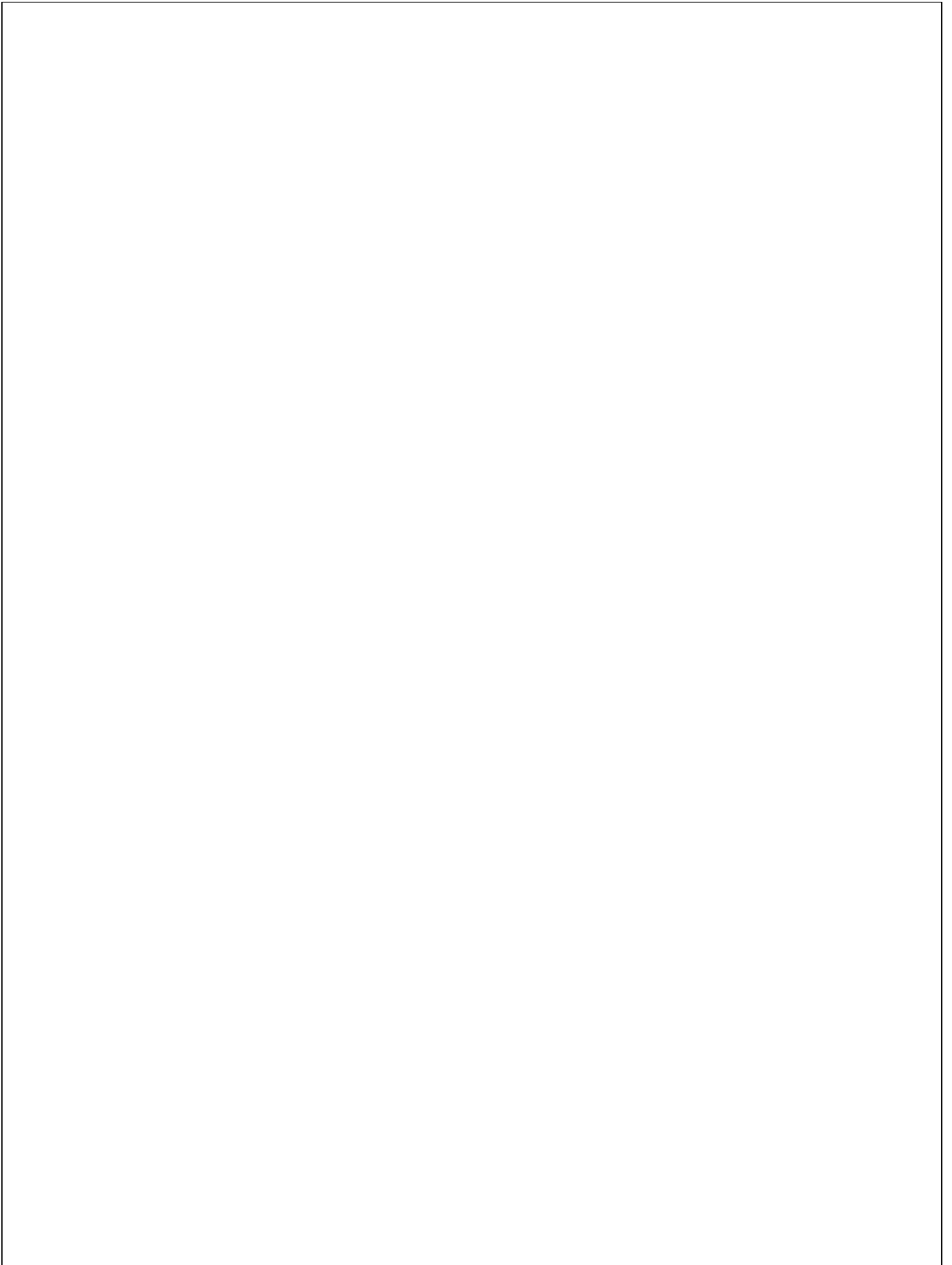
	Glossary of Terms for Notes
1.	Organization and Summary of Significant Accounting Policies
2.	New Accounting Standards
3.	Comprehensive Income
4.	Rate Matters
5.	Effects of Regulation
6.	Commitments, Guarantees and Contingencies
7.	Acquisitions and Impairments
8.	Benefit Plans
9.	Business Segments
10.	Derivatives and Hedging
11.	Fair Value Measurements
12.	Income Taxes
13.	Leases
14.	Voluntary Severance Program
15.	Financing Activities
16.	Related Party Transactions
17.	Property, Plant and Equipment
18.	Revenue from Contracts with Customers
19.	Resubmission Disclosure - Income Taxes

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASC	Accounting Standards Codification.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CEO	Chief Executive Officer.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CODM	Chief Operating Decision Maker.
CWIP	Construction Work in Progress.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
Diversion	Diversion, acquired in December 2024, consists of 201 MWs of wind generation in Texas.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Generally Accepted Accounting Principles in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the "Inflation Reduction Act" (IRA).
Term	Meaning
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
LPSC	Louisiana Public Service Commission.

LAUC	Louisiana Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NOL	Net operating losses.
NOLC	Net operating loss carryforward.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries.
PFDD	Proposal for Decision.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PLR	Private Letter Ruling.
PPA	Power Purchase Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
PUCT	Public Utility Commission of Texas.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Term	Meaning
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.



1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 555,000 retail customers in its service territory in northeastern and the panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

SWEPCo's rates are regulated by the FERC and the APSC, LPSC and PUCT. The FERC also regulates SWEPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. SWEPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that SWEPCo has "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are tied-up to actual costs annually.

The APSC, LPSC and PUCT regulate all of the retail distribution operations and rates of SWEPCo's retail public utility subsidiaries on a cost basis. The APSC, LPSC and PUCT also regulate the retail generation/power supply operations and rates.

The FERC also regulates SWEPCo's wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Bundled retail transmission rates are regulated by the APSC, LPSC and PUCT.

In addition, the FERC regulates the Operating Agreement and TCA, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. See Note 16 - Related Party Transactions for additional information.

Basis of Accounting

SWEPCo's accounting is subject to the requirements of the APSC, LPSC, PUCT and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The accounting for transactions with Sabine Mining Company as a nonaffiliated company rather than consolidating the entity in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of SPP purchases as operation expenses instead of a reduction in revenue.
- The classification of an accrued provision for potential refund as other noncurrent liability rather than a current liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The presentation of over/under fuel recovery in revenue rather than as a component operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of gas procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of accrued unbilled revenues as a current and accrued asset rather than netted against accounts payable for affiliated companies.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment - accumulated depreciation and amortization.

- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of unrecovered plant costs as accumulated depreciation instead of regulatory assets.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of the amortization of certain regulatory assets as regulatory debits and credits rather than depreciation and amortization.
- The presentation of certain regulatory balances as regulated liabilities instead of regulated assets.
- The accounting for transactions with SWEPco Storm Recovery Funding as a nonaffiliated company rather than consolidating the entity in accordance with the accounting guidance for “Variable Interest Entities.”

Accounting for the Effects of Cost-Based Regulation

SWEPco’s financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for “Regulated Operations,” regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for credit losses, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management’s evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

For the Years Ended December 31,	2024	2023
	(in millions)	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	\$ 137.9	\$ 123.5
Income Taxes (Net of Refunds)	(15.2)	(42.4)
Transferable Tax Credits	(88.6)	(41.4)
Noncash Acquisitions Under Finance Leases	2.3	7.1
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	137.3	63.7

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Credit Losses

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, SWEPco accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with SWEPco. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See “Securitized Accounts Receivable – AEP Credit” section of Note 15 for additional information.

Generally, AEP Credit recognizes bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from SWEPCo. The assessment is performed separately for SWEPCo, which inherently contemplates any differences in geographical risk characteristics for the allowance for credit losses.

For customer accounts receivable relating to risk management activities, accounts receivable are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for credit losses should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers

SWEPCo does not have any significant customers that comprise 10% or more of its operating revenues for the years ended December 31, 2024 and 2023.

SWEPCo monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The APSC, LPSC and PUCT allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying financial statements.

Renewable Energy Credits

SWEPCo records renewable energy credits (RECs) at cost. SWEPCo follows the inventory model for these RECs. RECs are reported in Miscellaneous Current and Accrued Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Operation Expenses at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are charged to accumulated depreciation.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Investment in Subsidiary Companies

SWEPCo has two wholly-owned subsidiaries, DHLC, which was engaged in lignite-mining operations until its closure in December 2021 and Southwest Arkansas Utilities Corporation, which is engaged in right of way acquisition. Investment in the net assets of DHLC is carried at cost plus equity in its undistributed earnings since acquisition. Investment in the net assets of Southwest Arkansas Utilities Corporation is carried at cost.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Asset Retirement Obligations

SWEPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, wind farms, and certain coal-mining facilities. SWEPCo also recorded AROs related to the Federal EPA's revised CCR Rule. For operating facilities, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired facilities, the present value of the liability is expensed, and where future recovery through rates is probable, the present value of the liability is subsequently deferred as a regulatory asset.

ARO are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned and the liabilities will be remediated as well as the inflation rate and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. SWEPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since SWEPCo plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when SWEPCo abandons or ceases the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, Notes Receivable from Associated Companies, Notes Payable to Associated Companies, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs

derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate and infrastructure investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the APSC, LPSC and PUCT. On a routine basis, the APSC, LPSC and PUCT review and/or audit SWEPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. SWEPCo shares the majority of its Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, non-existent or not applicable to merchant operations, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

SWEPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are reviewed for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

SWEPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. SWEPCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the APSC's, LPSC's and PUCT's regulatory treatment, SWEPCo does not include the fuel portion in unbilled revenue, but rather recognizes such revenues when billed to customers.

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by SWEPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by SWEPCo in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 18 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to SPP. SWEPCo also purchases power from SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to SPP, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, SWEPCo records expenses when purchased electricity is received and when expenses are incurred. SWEPCo defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

SWEPCo engages in power, capacity and, to a lesser extent, natural gas marketing as a major power producer and participant in electricity and natural gas markets. SWEPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent

markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

SWEPco recognizes revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

SWEPco uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on the balance sheets as Derivative Instrument Assets or Liabilities, as appropriate, and on the statements of income in Operating Revenues. SWEPco includes realized gains and losses on marketing and risk management transactions in revenue or expense based on the transaction's facts and circumstances. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event SWEPco designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, SWEPco subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 10 for additional information.

Maintenance

SWEPco expenses maintenance costs as incurred. If it becomes probable that SWEPco will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues. SWEPco defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment and Production Tax Credits

SWEPco uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost-of-service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

SWEPco applies the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by SWEPco. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as gross within the Supplementary Cash Flow Information.

SWEPco accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." SWEPco classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

SWEPco joins in the filing of a consolidated federal income tax return. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the SWEPco is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, Parent Company Loss Benefit and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes

As an agent for some state and local governments, SWEPco collects from customers certain excise taxes levied by those state or local governments on customers. SWEPco does not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility assets are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

SWEPco participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all SWEPco's employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. SWEPco also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees. SWEPco is allocated a proportionate share of benefit costs and accounts for its participation in the AEPSC sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.

- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	35 %
Fixed Income	49 %
Other Investments	15 %
Cash and Cash Equivalents	1 %
OPEB Plans Assets	Target
Equity	67 %
Fixed Income	32 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of the outstanding class of equity.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2024 and 2023, the fair value of securities on loan as part of the program was \$60 million and \$62 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2024 through February 13, 2025, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 8, 2025. This evaluation was updated through November 05, 2025 (for Note 19 only) for the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. NEW ACCOUNTING STANDARDS

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to SWEPCo's business. The following standards will impact SWEPCo's financial statements.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the CODM and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of

(c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

Management adopted ASU 2023-07 and its related implementation guidance effective January 1, 2024 for the annual reporting period and applied the amendments retrospectively to all prior periods presented in the consolidated financial statements. The amendments for interim periods will be adopted in our fiscal year beginning on January 1, 2025. The adoption of the new standard did not impact the results of operations, statements of financial position or cash flows.

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax, net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.

The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has concluded to adopt the amendments to this standard prospectively beginning on January 1, 2025.

ASU 2024-03 "Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures" (ASU 2024-03)

In November 2024, the FASB issued ASU 2024-03, the intent of which is to improve financial reporting and respond to investor input by requiring public business entities to disclose additional information about certain expenses in the notes to financial statements in interim and annual reporting periods. Among other provisions, the new standard requires disclosure of disaggregated amounts for expenses such as employee compensation, depreciation, and intangible asset amortization included in each expense caption presented on the face of the income statement. Public business entities are required to include certain amounts that are already required to be disclosed under GAAP in the same disclosure as the other disaggregation requirements as well as a qualitative description of any amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. The new standard also requires disclosure of the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. An entity is not precluded from providing additional voluntary disclosures that may provide investors with additional decision-useful information.

The amendments in the new standard are effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption permitted. The amendments in the new standard should be applied either prospectively to financial statements issued for reporting periods after the effective date or retrospectively to any or all prior periods presented in the financial statements. Management is evaluating the new standard and has not yet determined when, or the method by which, SWEPco will adopt its amendments.

3. COMPREHENSIVE INCOME

SWEPco's balance and activity in AOCI was not material for the years ended December 31, 2024 and 2023.

4. RATE MATTERS

SWEPco is involved in rate and regulatory proceedings at the FERC and the APSC, LPSC and PUCT. Rate matters can have a material impact on net income, cash flows and possibly financial condition. SWEPco's recent significant rate orders and pending rate filings are addressed in this note.

2012 Texas Base Rate Case

In 2012, SWEPco filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPco's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPco reversed \$114 million of a previously recorded regulatory disallowance in 2013. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. In November 2021, SWEPco and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPco and the PUCT. In December 2022, SWEPco and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPco's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPco filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

In December 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPco's request that would allow the PUCT to find cause to allow SWEPco to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPco recorded a pretax, non-cash probable disallowance of \$86 million in the fourth quarter of 2023.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. On March 1, 2024, SWEPco filed supplemental direct testimony with the PUCT in response to the December 2023 preliminary order. On March 8, 2024, intervenors and the PUCT staff filed a motion with the PUCT to strike portions of SWEPco's October 2023 direct testimony and March 2024 supplemental direct testimony. On March 19, 2024, the ALJ granted portions of the motion, which included removal of testimony supporting SWEPco's position that refunds were not appropriate. On March 28, 2024, SWEPco filed an appeal of the ALJ decision with the PUCT. In April 2024, intervenors and PUCT staff submitted testimony recommending customer refunds through December 2023 ranging from \$149 million to \$197 million, including carrying charges, with refund periods ranging from 18 months to 48 months. In May 2024, the PUCT denied SWEPco's appeal of the ALJ's March 2024 decision. In the second quarter of 2024, based on the PUCT's decision, SWEPco recorded a one-time, probable revenue refund provision of \$160 million, including interest, associated with revenue collected from February 2013 through December 2023. In June 2024, SWEPco and parties to the remand proceeding reached an agreement in principle that would resolve all issues in the case. In October 2024, SWEPco filed the settlement agreement with the PUCT. Under the settlement agreement, SWEPco would refund, over a two-year period, \$148 million, including interest, associated with revenue collected from February 2013 through December 2023 and remove AFUDC in excess of the Texas jurisdictional capital cost cap from rate base. In January 2025, the settlement agreement was approved by the PUCT.

2010 Texas Base Rate Case

In 2016, SWEP Co filed a request with the PUCT for a net increase in Texas annual revenues of \$69 million based upon a 10% ROE. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of \$50 million based upon a 9.6% ROE, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in-service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of \$2 million in additional vegetation management expenses and (d) the rejection of SWEP Co's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEP Co: (a) recorded an impairment charge of \$19 million, which included \$7 million associated with the lack of return on Welsh Plant, Unit 2 and \$12 million related to other disallowed plant investments, (b) recognized \$32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional \$7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEP Co implemented new rates in February 2018 billings. The \$32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order was appealed by various intervenors related to limiting SWEP Co's recovery of AFUDC on Turk Plant and recovery of Welsh Plant, Unit 2. In December 2024, the appeal was dismissed. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2020 Texas Base Rate Case

In October 2020, SWEP Co filed a request with the PUCT for a \$105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of \$90 million primarily due to increased investments. SWEP Co subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to \$100 million which would result in an \$85 million net annual base rate increase after moving the proposed riders to rate base.

In January 2022, the PUCT issued a final order approving an annual revenue increase of \$39 million based upon a 9.25% ROE. The order also includes: (a) rates implemented retroactively back to March 18, 2021, (b) \$5 million of the proposed increase related to vegetation management, (c) \$2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider to recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value to be recovered as a regulatory asset through 2046. As a result of the final order, SWEP Co recorded a disallowance of \$12 million in 2021 associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEP Co filed a motion for rehearing with the PUCT challenging several errors in the order, which include challenges of the approved ROE, the denial of a reasonable return or carrying costs on the Dolet Hills Power Station and the calculation of the Texas jurisdictional share of the storm catastrophe reserve. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEP Co filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order.

2021 Louisiana Storm Cost Filing

In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEP Co service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEP Co, to establish regulatory assets to track and defer expenses associated with these storms. In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm. In March 2023, SWEP Co and the LPSC staff filed a joint stipulation and settlement agreement with the LPSC which confirmed the prudence of \$150 million of deferred incremental storm restoration expenses. The agreement also authorized an interim carrying charge at a rate of 3.125% through March 2024. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement. In July 2023, SWEP Co submitted additional information in phase two of this proceeding to obtain a financing order and prudence review of capital investment. In April 2024, SWEP Co and the LPSC staff filed a joint uncontested stipulation and settlement agreement with the LPSC requesting securitization of storm costs, including a storm reserve. In July 2024, the LPSC issued an order approving the joint uncontested stipulation and settlement agreement. In December 2024, SWEP Co issued \$337 million of securitization bonds. The securitization bonds included \$180 million for storm costs related to Hurricanes Laura and Delta and \$150 million related to a storm reserve. In June 2023, SWEP Co incurred approximately \$44 million in storm costs impacting the Louisiana jurisdiction. As authorized by the LPSC, the June 2023 storm costs were applied against the \$150 million storm reserve. Any costs applied against the remaining storm reserve are subject to audit and prudence reviews. SWEP Co is required to accrue carrying charges on the remaining storm reserve liability. The securitization bonds also included \$7 million related to estimated financing costs and carrying charges.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021, to February 20, 2021, SWEP Co's natural gas expenses and purchases of electricity still to be recovered from customers are shown in the table below:

Jurisdiction	December 31,		2023	Approved Recovery Period	Approved Carrying Charge	
	2024	(in millions)				
Arkansas	\$	37.2	\$	54.2	6 years	(a)
Louisiana		70.6		97.2	(b)	(b)
Texas		72.7		101.9	5 years	1.65%
Total	\$	180.5	\$	253.3		

(a) SWEP Co is permitted to record carrying costs on the unrecovered balance of fuel costs at a weighted-cost of capital approved by the APSC. In August 2024, the APSC issued an order that found SWEP Co had prudently incurred these costs.

(b) In March 2021, the LPSC approved a special order granting a temporary modification to the FAC and shortly after SWEP Co began recovery of its Louisiana jurisdictional share of these fuel costs based on a five-year recovery period inclusive of an interim carrying charge equal to the prime rate. The special order states the fuel and purchased power costs incurred will be subject to a future LPSC audit.

If SWEP Co is unable to recover any of the costs relating to the extraordinary fuel and purchases of electricity, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

SWEP Co constructed the Turk Plant, a base load 600 MW (650 MW net maximum capacity) pulverized coal ultra-supercritical generating unit in Arkansas, which was placed in-service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEP Co owns 73% (440 MWs/477 MWs) of the Turk Plant and operates the facility. As of December 31, 2024, the net book value of the Turk Plant was \$1.3 billion, before cost of removal including CWIP and inventory.

Approximately 20% of SWEP Co's portion of the Turk Plant output is currently not subject to cost-based rate recovery in Arkansas. This portion of the plant's output is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under retail cost-based rate recovery in Texas, Louisiana and through SWEP Co's wholesale customers under FERC-approved rates. In November 2022, SWEP Co filed a Certificate of Public Convenience and Necessity with the APSC for approval to operate the Turk Plant to serve Arkansas customers and recover the associated costs

through a cost recovery rider. Cost-based recovery of the Turk Plant would aid SWEP Co's near-term capacity needs and support compliance with SPP's 2023 increased capacity planning reserve margin requirements. In April 2023, intervenors filed testimony recommending the APSC deny the Certificate of Public Convenience and Necessity on the basis that the Turk Plant is not the least cost alternative. In March 2024, the APSC issued an order denying SWEP Co's request to allow the merchant portion of the Turk Plant to serve Arkansas customers. As a result of the APSC's March 2024 order, SWEP Co recorded a \$32 million favorable impact to net income as a result of the reduction to the regulatory liability related to the merchant portion of Turk Plant Excess ADIT.

2024 Texas Fuel Reconciliation

In June 2024, SWEPCo filed a fuel reconciliation with the PUCT for its retail operation in Texas for the period of January 2022 through December 2023. The fuel reconciliation included approximately \$535 million in Texas jurisdictional eligible fuel costs. In January 2025, intervenors filed testimony recommending a disallowance of Texas jurisdictional fuel costs ranging from \$2 million to \$25 million related to the decision made by SWEPCo to retire the Pirkey Plant, management of fuel inventory and SWEPCo's energy price offers in SPP. Also, in January 2025, the PUCT staff filed testimony agreeing with SWEPCo's filed fuel reconciliation. In February 2025, SWEPCo filed rebuttal testimony explaining why there should be no disallowance.

North Central Wind Energy Facilities (NCWF)

The NCWF are subject to various regulatory performance requirements, including a Net Capacity Factor (NCF) guarantee. The NCF guarantee will be measured in MWhs across all facilities on a combined basis for each five year period for the first thirty full years of operation. The first NCF guarantee five year period began in April 2022. Certain wind turbines have experienced performance issues related to defects covered by the manufacturer's warranty. These performance issues have prompted SWEPCo to file a lawsuit against the manufacturer in an attempt to find a resolution on the matter. If regulatory performance requirements, such as the NCF guarantee, are not met, SWEPCo may recognize a regulatory liability associated with a refund to retail customers. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

SWEPCo and other AEP subsidiaries transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements, and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2024, 2023, 2022 and 2021 by \$52 million, \$61 million, \$69 million and \$78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. Accordingly, in the third quarter of 2024, the AEP transmission owning subsidiaries within SPP provided a portion of the 2021 rate year refunds, with the remainder of the refunds expected to be provided in 2025. The AEP transmission owning subsidiaries within PJM are expected to provide their respective refunds for the 2021 rate year in 2025. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEPSC made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. In May 2024, AEPSC filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking review of the FERC's January 2024 and March 2024 decisions. In July 2024, the FERC issued orders approving AEPSC's request to reopen the record for the limited purpose of accepting into the record the IRS PLRs and establish additional briefing procedures. In August 2024, AEPSC filed briefs with the FERC requesting the commission modify or overturn their initial orders.

As a result of the January 2024 FERC orders, the Registrants' balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. SWEPCo has not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years. The probable refunds to affiliated and nonaffiliated customers are reflected as Accumulated Provision for Rate Refunds on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Miscellaneous Current and Accrued Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Other Regulatory Liabilities or a reduction to Other Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

Request to Update SWEPCo Generation Depreciation Rates

In October 2023, SWEPCo filed an application to revise its generation wholesale customer's contracts to reflect an increase in the annual revenue requirement of approximately \$5 million for updated depreciation rates and allow for the return on and of FERC customers jurisdictional share of regulatory assets associated with retired plants. In November 2023, certain intervenors filed a motion with the FERC protesting and recommending the rejection of SWEPCo's filings. In December 2023, the FERC issued an order approving the proposed rates effective January 1, 2024, subject to further review and refund and established hearing and settlement proceedings. If SWEPCo is unable to recover the remaining regulatory assets associated with retired plants, or refunds of revenues collected under interim rates are ordered to be returned, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

Regulated Generating Units

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations in balance with reliability and other factors, which has resulted in, and in the future may result in, a proposal to retire generating facilities earlier than their currently estimated useful lives.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets is not deemed recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

In December 2021, the Dolet Hills Power Station was retired. As part of the 2020 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo's Texas jurisdictional share of the Dolet Hills Power Station through 2046, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of \$12 million in 2021. See "2020 Texas Base Rate Case" section of Note 4 for additional information. As part of the 2021 Arkansas Base Rate Case, the APSC authorized recovery of SWEPCo's Arkansas jurisdictional share of the Dolet Hills Power Station through 2027, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of \$2 million in the second quarter of 2022. Also, the APSC did not rule on the prudence of the early retirement of the Dolet Hills Power Station, which will be addressed in a future proceeding. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana share of the Dolet Hills Power Station, through a separate rider, through 2032, but did not rule on the prudence of the early retirement of the plant, which is being addressed in a separate proceeding. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the prudence of the retirement of the Dolet Hills Power Station and resulted in a disallowance of \$14 million in the first quarter of 2024.

In March 2023, the Pirkey Plant was retired. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo's Louisiana jurisdictional share of the Pirkey Plant, through a separate rider, through 2032. As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. In July 2023, Texas ALJs issued a PFD that concluded the decision to retire the Pirkey Plant was prudent. In September 2023, the PUCT rejected the ALJs' July 2023 PFD. In the open meeting, the commissioners expressed their concerns that the analysis in support of SWEPCo's decision to retire the Pirkey Plant was not robust enough and that SWEPCo should have re-evaluated the decision following Winter Storm Uri. The treatment of the cost of recovery of the Pirkey Plant is expected to be addressed in a future rate case. As of December 31, 2024, the Texas jurisdictional share of the net book value of the Pirkey Plant was \$69 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Unit to be Retired

In November 2020, management announced that it will cease using coal at the Welsh Plant in 2028. As a result of the announcement, SWEPCo began recording a regulatory asset for accelerated depreciation. In December 2024, SWEPCo filed an application for a Certificate of Convenience and Necessity (CCN) with the APSC, LPSC and PUCT to convert Welsh Plant, Units 1 and 3 to natural gas in 2028 and 2027, respectively.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2024, of Welsh Plant, Units 1 and 3:

Net Book Value	Accelerated Depreciation	Cost of Removal	Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (a)
(dollars in millions)					
\$ 324.3	\$ 168.6	\$ 57.6	(b) 2028	(c) (d)	\$ 43.6

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.

(b) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with the removal of Welsh Plant, Units 1 and 3, after retirement.

(c) Represents projected retirement date of coal assets.

(d) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

Dolet Hills Power Station and Related Fuel Operations

In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station. The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through rate riders. As of December 31, 2024, SWEPCo's share of the net investment in the Dolet Hills Power Station was \$74 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudence determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of December 31, 2024, SWEPCo had a net under-recovered fuel balance of \$22 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to \$20 million of fuel costs in 2021 and defer approximately \$35 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of up to \$55 million, including denial of recovery of the \$35 million deferral, with refunds to customers over five years. In February 2024, an ALJ issued a final recommendation which included a proposed \$55 million refund to customers and the denial of recovery of the \$35 million deferral. SWEPCo filed a motion to present oral arguments with the LPSC to dispute the ALJ's recommendations. In April 2024, the LPSC approved a unanimous settlement agreement filed by SWEPCo, LPSC staff and certain intervenors that resolved the fuel recovery dispute and resulted in a fuel disallowance of \$11 million. The remaining \$24 million regulatory asset balance will be recovered over three years with interest.

In March 2021, the APSC approved fuel rates that provide recovery of \$20 million for the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of \$48 million of Oxbow mine related costs through 2035.

If any of these costs are not recoverable or customer refunds are required, it could reduce future net income and cash flows and impact financial condition.

Pirkey Plant and Related Fuel Operations

In March 2023, the Pirkey Plant was retired. SWEPCo is recovering, or will seek recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of December 31, 2024, SWEPCo's share of the net investment in the Pirkey Plant was \$188 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information. Fuel costs are recovered through active fuel clauses and are subject to prudence determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of December 31, 2024, SWEPCo had a net under-recovered fuel balance of \$22 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Remaining operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses.

In July 2023, the LPSC ordered that a separate proceeding be established to review the prudence of the decision to retire the Pirkey Plant, including the costs included in fuel for years starting in 2019 and after. In November 2024, the LPSC staff submitted testimony recommending a \$5 million fuel disallowance and a lower return on the remaining Pirkey Plant balance or recovery of the retired plant balance at a rate less than SWEPCo's weighted average cost of capital. In December 2024, SWEPCo filed its rebuttal testimony explaining why there should be no disallowance. A hearing is scheduled for March 2025.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of \$33 million of Sabine related fuel costs through 2035. In June 2024, SWEPCo filed a fuel reconciliation with the PUCT for its retail operation in Texas for the period of January 2022 through December 2023. In January 2025, intervenors filed testimony recommending a disallowance for fuel costs ranging from \$2 million and \$25 million related to SWEPCo's decision to retire the Pirkey Plant, management of fuel inventory and SWEPCo's energy price offers in SPP. Also, in January 2025, the PUCT staff filed testimony agreeing with SWEPCo's filed fuel reconciliation. In February 2025, SWEPCo filed rebuttal testimony explaining why there should be no disallowance.

If any of these costs are not recoverable or customer refunds are required, it could reduce future net income and cash flows and impact financial condition.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31,		Remaining Recovery Period
	2024	2023	
(in millions)			
Regulatory Assets:			
Regulatory assets pending final regulatory approval:			
<u>Regulatory Assets Currently Earning a Return</u>			
Pirkey Plant Accelerated Depreciation - Arkansas	\$ 36.9	\$ 35.2	
Unrecovered Winter Storm Fuel Costs (a)	33.5	60.1	
NOLC Carrying Charges	—	15.5	
Other Regulatory Assets Pending Final Regulatory Approval	10.8	26.0	
Total Regulatory Assets Currently Earning a Return	81.2	136.8	
<u>Regulatory Assets Currently Not Earning a Return</u>			
NOLC - Costs (b)	67.0	—	
Storm-Related Costs - Louisiana Texas	39.9	56.0	

Other Regulatory Assets Pending Final Regulatory Approval	18.7	13.7	
Total Regulatory Assets Currently Not Earning a Return	125.6	69.7	
Total Regulatory Assets Pending Final Regulatory Approval	206.8	206.5	
Regulatory assets approved for recovery:			
<u>Regulatory Assets Currently Earning a Return</u>			
Unrecovered Winter Storm Fuel Costs (a)	147.0	193.2	3 years
Fuel Mine Closure Costs - Texas	70.6	74.3	11 years
Pirkey Plant Accelerated Depreciation - Louisiana	66.4	65.8	8 years
Under-recovered Fuel Costs (c)	22.3	76.9	1 year
Dolet Hills Power Station Fuel Costs - Louisiana	21.7	—	3 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station - Louisiana	19.0	40.8	8 years
Storm-Related Costs - Louisiana (d)	—	144.7	
Other Regulatory Assets Approved for Recovery	12.6	13.9	various
Total Regulatory Assets Currently Earning a Return	359.6	609.6	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Income Tax Assets	245.9	285.9	(e)
Pension and OPEB Funded Status	83.5	99.9	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	44.5	48.7	22 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	12.8	17.3	3 years
Unrealized Loss on Forward Commitments	1.2	15.4	3 years
North Central Wind Rider	—	20.2	
Other Regulatory Assets Approved for Recovery	18.6	26.1	various
Total Regulatory Assets Currently Not Earning a Return	406.5	513.5	
Total Regulatory Assets Approved for Recovery	766.1	1,123.1	
Total FERC Account 182.3 Regulatory Assets	\$ 972.9	\$ 1,329.6	

- (a) See "February 2021 Severe Winter Weather Impacts in SPP" section of Note 4 for additional information.
- (b) In the second quarter of 2024, a request seeking to establish a recovery mechanism for the Texas jurisdictional share of these regulatory assets was filed in Texas. In the third quarter of 2024, PUCT Staff and certain intervenors in Texas requested a hearing and direct testimony was filed by SWEPCo in October 2024. A hearing is scheduled for the first quarter of 2025 in Texas.
- (c) 2024 amount related to Arkansas, Louisiana and Texas jurisdictions. 2023 amount related to Arkansas and Texas jurisdictions.
- (d) In July 2024, the LPSC approved SWEPCo's securitization of storm costs for Hurricanes Laura and Delta, as well as a storm reserve. See "2021 Louisiana Storm Cost Filing" section of Note 4 for additional information.
- (e) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

	December 31,		Remaining Refund Period
	2024	2023	
Regulatory Liabilities:	(in millions)		
Regulatory liabilities pending final regulatory determination:			
<u>Regulatory Liabilities Currently Paying a Return</u>			
NOLC Carrying Charges	\$ —	\$ 15.5	
Income Tax Liabilities (a)	7.0	7.0	
Total Regulatory Liabilities Currently Paying a Return	7.0	22.5	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
NOLC - Costs	17.4	—	
Total Regulatory Liabilities Currently Not Paying a Return	17.4	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	24.4	22.5	
Regulatory liabilities approved for payment:			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Income Tax Liabilities (a)	373.3	578.3	(b)
Over-recovered Fuel Costs (c)	21.6	3.4	1 year
Other Regulatory Liabilities Approved for Payment	7.3	4.3	various
Total Regulatory Liabilities Currently Paying a Return	402.2	586.0	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Other Regulatory Liabilities Approved for Payment	12.4	8.9	various
Total Regulatory Liabilities Currently Not Paying a Return	12.4	8.9	
Total Regulatory Liabilities Approved for Payment	414.6	594.9	
Total FERC 254 Account Regulatory Liabilities	\$ 439.0	\$ 617.4	

- (a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
- (b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets.
- (c) 2024 amount related to Texas jurisdiction. 2023 amount related to Louisiana jurisdiction.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

SWEPCo is subject to certain claims and legal actions arising in the ordinary course of business. In addition, SWEPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

SWEPco has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for “Commitments”, the following table summarizes SWEPco’s actual contractual commitments as of December 31, 2024:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
	(in millions)				
Fuel Purchase Contracts (a)	\$ 89.4	\$ 46.6	\$ —	\$ —	\$ 136.0
Energy and Capacity Purchase Contracts	11.5	13.2	—	—	24.7
Total	\$ 100.9	\$ 59.8	\$ —	\$ —	\$ 160.7

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for “Guarantees.” There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Indemnifications and Other Guarantees

Contracts

SWEPco enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2024, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase-and-sale activity on behalf of PSO and SWEPco, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

SWEPco leases equipment under master lease agreements. See “Master Lease Agreements” section of Note 13 for additional information.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants)

Federal EPA’s Revised CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities (“legacy CCR surface impoundments”) as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land (“CCR management units”). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material (“closure in place”) or the CCR material may be excavated and placed in a compliant landfill (“closure by removal”). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. AEP evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the revised CCR Rule.

Increase in ARO	Increase in Utility Plant (a)
(in millions)	
\$ 23.8	\$ 23.8

(a) ARO is related to a legacy CCR surface impoundment or CCR management unit at an operating generation facility.

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items. These future changes could have a material impact on the ARO and materially reduce future net income and cash flows and further impact financial condition.

AEP will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. Several parties, including AEP and one of its trade associations, have filed petitions for review of the rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the rule pending the outcome of the litigation. In November 2024, the court denied the stay motion. Management cannot predict the outcome of the litigation.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. SWEPco currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2024, SWEPco was named as a Potentially Responsible Party (PRP) for one site by the Federal EPA for which alleged liability is unresolved. There are three additional sites for which SWEPco received information requests which could lead to PRP designation. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but cannot provide statements on the amount of potential future liability. All parties that material were disposed of at

management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2024, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

SWEPCo maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. SWEPCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cybersecurity incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by SWEPCo. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

In July 2024, SWEPCo renewed insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident, extreme weather or wildfire related liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through the rate-making process, could reduce future net income and cash flows and impact financial condition.

7. ACQUISITIONS AND IMPAIRMENTS

ACQUISITIONS

Diversion Wind Farm

In December 2024, SWEPCo acquired 100% of the equity interests in Diversion Wind Energy, LLC, the owner of Diversion wind farm. The Diversion wind farm is a newly constructed 201 MW wind facility located in Baylor County, Texas and was placed in service in December 2024. Output from Diversion serves FERC wholesale load and retail customers in Arkansas and Louisiana. SWEPCo's Louisiana jurisdictional share of the Diversion revenue requirement, net of PTC benefit, is recoverable through an authorized rider until the amounts are reflected in base rates. Recovery of the Arkansas portion of the Diversion revenue requirement is expected to begin in 2026 through base rates. Regulatory commission approval of the inclusion of the output from Diversion in retail rates resulted in various capital cost, performance and other guarantees for retail customers which could subject SWEPCo to future regulatory liabilities to retail customers.

In accordance with the guidance for "Business Combinations," management determined that the acquisition of the Diversion project represents an asset acquisition. As of December 31, 2024, SWEPCo had approximately \$423 million of gross Utility Plant, inclusive of capital expenditures after the acquisition, on the balance sheets related to the Diversion project. The acquisition also resulted in the recognition of \$20 million of operating leases that provide for easement and access rights to the land that Diversion was built upon and \$6 million of AROs.

IMPAIRMENTS

2012 Texas Base Rate Case

In December 2023, SWEPCo recorded a pretax, non-cash disallowance of \$86 million in Other Deductions on the statements of income due to regulatory disallowance of recovery of AFUDC on Turk Plant in the 2012 Texas Base Rate case. See the "2012 Texas Base Rate Case" section of Note 4 for additional information.

2020 Texas Base Rate Case

In January 2022, the PUCT issued a final order which included a return of investment only for the recovery of the Dolet Hills Power Station. As a result of the final order, SWEPCo recorded a disallowance of \$12 million associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging denial of a reasonable return or carrying costs on the Dolet Hills Power Station among other items. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order. See "2020 Texas Base Rate Case" section of Note 4 for additional information.

8. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

SWEPCo participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. SWEPCo also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees.

SWEPCo recognizes the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. SWEPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. SWEPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for rate-making purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of benefit obligations are shown in the following table:

Assumption	Pension Plans		OPEB	
	December 31,			
	2024	2023	2024	2023
Discount Rate	5.65 %	5.15 %	5.60 %	5.15 %
Interest Crediting Rate	4.55 %	4.00 %	NA	NA
Rate of Compensation Increase	5.55 % (a)	5.00 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2024, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

Assumption	Pension Plans		OPEB	
	Year Ended December 31,			
	2024	2023	2024	2023
Discount Rate	5.20 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.05 %	4.25 %	NA	NA
Expected Return on Plan Assets	7.30 %	7.50 %	6.75 %	7.25 %
Rate of Compensation Increase	5.10 % (a)	5.00 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31, 2024	December 31, 2023
Initial	6.50 %	7.00 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	2030

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2024, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2024, the pension plans had an actuarial gain primarily due to an increase in discount rates, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2024). These gains were partially offset by increasing the cash balance account interest crediting rate, increasing the rate used to convert lump sums to annuities and updating the compensation increase rate to reflect the results of an experience study conducted in 2024. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and updated discount rates. These gains were partially offset by the addition of a life insurance administrative load of 5%, the effect of special termination benefits and earlier retirements due to the voluntary severance program that occurred in the second quarter of 2024 and assumption changes as a result of an experience study conducted in 2024. For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

Change in Benefit Obligation	Pension Plans		OPEB	
	2024	2023	2024	2023
	(in millions)			
Benefit Obligation as of January 1,	\$ 261.2	\$ 250.7	\$ 53.7	\$ 55.1
Service Cost	7.8	7.7	0.4	0.4
Interest Cost	12.5	13.9	2.7	2.9
Actuarial (Gain) Loss	(11.2)	16.8	(11.5)	1.2
Settlements	(33.1)	—	—	—
Special/Contractual Termination Benefits	—	—	0.3	—
Benefit Payments	(9.4)	(27.9)	(7.4)	(8.8)
Participant Contributions	—	—	3.3	2.9
Benefit Obligation as of December 31,	\$ 227.8	\$ 261.2	\$ 41.5	\$ 53.7

Change in Fair Value of Plan Assets	Pension Plans		OPEB	
	2024	2023	2024	2023
Fair Value of Plan Assets as of January 1,	\$ 227.5	\$ 231.3	\$ 111.1	\$ 103.0
Actual Gain on Plan Assets	3.6	23.9	14.2	14.0
Company Contributions	0.2	0.2	—	—
Settlements	(33.1)	—	—	—
Participant Contributions	—	—	3.3	2.9
Benefit Payments	(9.4)	(27.9)	(7.4)	(8.8)
Fair Value of Plan Assets as of December 31,	\$ 188.8	\$ 227.5	\$ 121.2	\$ 111.1

Funded (Underfunded) Status as of December 31,	\$ (39.0)	\$ (33.7)	\$ 79.7	\$ 57.4
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	Pension Plans		OPEB	
	2024	2023	2024	2023
	(in millions)			
Special Funds – Prepaid Benefit Costs	\$ —	\$ —	\$ 79.7	\$ 57.4
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	(0.1)	(0.1)	—	—

Accumulated Provision for Pensions and Benefits – Long-term

Benefit Liability	(38.9)	(33.6)	—	—
Funded (Underfunded) Status	\$ (39.0)	\$ (33.7)	\$ 79.7	\$ 57.4

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

Components	Pension Plans		OPEB	
	2024	2023	2024	2023
	(in millions)			
Net Actuarial Loss	\$ 82.9	\$ 89.6	\$ —	\$ 18.4
Prior Service Credit	—	—	(1.0)	(2.1)
Recorded as				
Regulatory Assets	\$ 83.0	\$ 89.7	\$ 0.5	\$ 10.2
Deferred Income Taxes	—	—	(0.3)	1.3
Net of Tax AOCI	(0.1)	(0.1)	(1.2)	4.8

Components	Pension Plans		OPEB	
	2024	2023	2024	2023
	(in millions)			
Actuarial (Gain) Loss During the Year	\$ 2.7	\$ 12.1	\$ (18.1)	\$ (5.6)
Amortization of Actuarial Loss	(0.1)	(0.1)	(0.3)	(1.0)
Amounts Recognized Due to Settlement	(9.3)	—	—	—
Amortization of Prior Service Credit	—	—	1.1	4.9
Change for the Year Ended December 31,	\$ (6.7)	\$ 12.0	\$ (17.3)	\$ (1.7)

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to SWEPCo using the percentages in the table below:

Pension Plan	OPEB	
	2024	2023
	December 31,	
	2024	2023
	5.2 %	5.5 %
	2024	2023
	6.8 %	6.6 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	December 31, 2024				Total	Year End Allocation
	Level 1	Level 2	Level 3	Other		
	(in millions)					
Equities (a):						
Domestic	\$ 327.0	\$ —	\$ —	\$ —	\$ 327.0	8.9 %
International	290.2	—	—	—	290.2	7.9 %
Common Collective Trusts (b)	176.1	—	—	472.6	648.7	17.7 %
Subtotal – Equities	793.3	—	—	472.6	1,265.9	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2.3)	865.6	—	—	863.3	23.6 %
Corporate Debt	—	719.2	—	—	719.2	19.6 %
Foreign Debt	—	136.1	—	—	136.1	3.7 %
State and Local Government	—	25.8	—	—	25.8	0.7 %
Other – Asset Backed	—	0.9	—	—	0.9	— %
Subtotal – Fixed Income	(2.3)	1,747.6	—	—	1,745.3	47.6 %
Infrastructure (b)	—	—	—	112.9	112.9	3.1 %
Real Estate (b)	—	—	—	227.9	227.9	6.2 %
Alternative Investments (b)	—	—	—	223.8	223.8	6.1 %
Cash and Cash Equivalents (b)	—	41.3	—	27.2	68.5	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21.9	21.9	0.6 %
Total	\$ 791.0	\$ 1,788.9	\$ —	\$ 1,086.3	\$ 3,666.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the “Investments Held in Trust for Future Liabilities” section of Note 1 for additional information.

(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.

(c) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Year End

Asset Class	Level 1	Level 2	Level 3	Other	Total	Allocation
	(in millions)					
Equities:						
Domestic	\$ 616.8	\$ —	\$ —	\$ —	\$ 616.8	34.7 %
International	267.2	—	—	—	267.2	15.0 %
Common Collective Trusts (a)	64.2	—	—	129.4	193.6	10.9 %
Subtotal – Equities	948.2	—	—	129.4	1,077.6	60.6 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	132.9	132.9	7.5 %
United States Government and Agency Securities	(0.5)	157.6	—	—	157.1	8.9 %
Corporate Debt	—	132.3	—	—	132.3	7.5 %
Foreign Debt	—	27.1	—	—	27.1	1.5 %
State and Local Government	57.8	5.0	—	—	62.8	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	57.3	322.2	—	132.9	512.4	28.9 %
Trust Owned Life Insurance:						
International Equities	—	23.1	—	—	23.1	1.3 %
United States Bonds	—	118.2	—	—	118.2	6.7 %
Subtotal – Trust Owned Life Insurance	—	141.3	—	—	141.3	8.0 %
Cash and Cash Equivalents (a)	27.6	—	—	3.1	30.7	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	13.9	13.9	0.8 %
Total	\$ 1,033.1	\$ 463.5	\$ —	\$ 279.3	\$ 1,775.9	100.0 %

(a) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.

(b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities (a):						
Domestic	\$ 411.3	\$ —	\$ —	\$ —	\$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	\$ 809.4	\$ 2,252.1	\$ 0.1	\$ 1,056.6	\$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the “Investments Held in Trust for Future Liabilities” section of Note 1 for additional information.

(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.

(c) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities:						
Domestic	\$ 540.6	\$ —	\$ —	\$ —	\$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %

Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	\$ 897.8	\$ 501.2	\$ —	\$ 274.3	\$ 1,673.3	100.0 %

(a) Amounts in “Other” column represent investments for which fair value is measured using net asset value per-share.

(b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31,	
	2024	2023
	(in millions)	
Qualified Pension Plan	\$ 209.5	\$ 241.9
Nonqualified Pension Plans	1.0	1.0
Total	\$ 210.5	\$ 242.9

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	December 31,	
	2024	2023
	(in millions)	
Projected Benefit Obligation	\$ 227.8	\$ 261.2
Fair Value of Plan Assets	188.8	227.5
Underfunded Projected Benefit Obligation	\$ (39.0)	\$ (33.7)

Accumulated Benefit Obligation

	December 31,	
	2024	2023
	(in millions)	
Accumulated Benefit Obligation	\$ 210.5	\$ 242.9
Fair Value of Plan Assets	188.9	227.5
Underfunded Accumulated Benefit Obligation	\$ (21.6)	\$ (15.4)

Estimated Future Benefit Payments and Contributions

SWEP Co expects contributions and payments for the pension plans of \$8.8 million during 2025. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, SWEP Co may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from SWEP Co’s assets. The payments include the participants’ contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	Estimated Payments	
	Pension Plans	OPEB
	(in millions)	
2025	\$ 20.7	\$ 8.6
2026	19.2	8.3
2027	20.4	8.0
2028	19.4	8.0
2029	19.0	7.8
Years 2030 to 2034, in Total	88.4	35.7

Components of Net Periodic Benefit Cost

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Years Ended December 31,			
	2024	2023	2024	2023
	(in millions)			
Service Cost	\$ 7.8	\$ 7.7	\$ 0.4	\$ 0.4
Interest Cost	12.5	13.9	2.7	2.9
Expected Return on Plan Assets	(17.4)	(19.4)	(7.5)	(7.2)
Amortization of Prior Service Credit	—	—	(1.1)	(4.9)
Amortization of Net Actuarial Loss	0.1	0.1	0.3	1.0
Settlements (a)	9.3	—	—	—
Special/Contractual Termination Benefits	—	—	0.3	—
Net Periodic Benefit Cost (Credit)	12.3	2.3	(4.9)	(7.8)
Capitalized Portion	(3.1)	(3.0)	(0.2)	(0.2)
Net Periodic Benefit Cost (Credit) Recognized in Expense	\$ 9.2	\$ (0.7)	\$ (5.1)	\$ (8.0)

(a) AEP will seek recovery for the portion of pension settlement costs related to regulated operations.

American Electric Power System Retirement Savings Plan

SWEPCo participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plans for the years ended December 31, 2024 and 2023 were \$7 million and \$7 million, respectively.

9. BUSINESS SEGMENTS

SWEPCo has one reportable segment, an electricity generation, transmission and distribution business. SWEPCo's other activities are insignificant. SWEPCo's operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results. The CODM of SWEPCo is the AEP President and CEO, who makes operating decisions, allocates resources to and assesses performance based on these reportable segments. The CODM uses net income (loss) that is reported on the SWEPCo's statements of income as a measure of segment profit or loss in making these decisions. Net income (loss) includes intercompany revenues and expenses that are eliminated on the consolidated financial statements. The expenses disclosed on SWEPCo's statements of income align with the segment-level significant expenses that are regularly provided to the CODM. Total Assets is reported on the consolidated financial statements. Gross Additions to Plants for SWEPCo is represented by the sum of Construction and Acquisition of Plant on the financial statements. See SWEPCo's statements of income, balance sheets and cash flows for details.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of SWEPCo.

SWEPCo is exposed to certain market risks as major power producer and participant in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact SWEPCo due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, SWEPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

SWEPCo utilizes power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. SWEPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. SWEPCo also utilizes derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following table represents the gross notional volume of SWEPCo's outstanding derivative contracts:

Primary Risk Exposure	Notional Volume of Derivative Instruments		Unit of Measure
	2024	2023	
	(in millions)		
Commodity:			
Power	4.6	2.9	MWhs
Natural Gas	15.4	17.9	MMBtus
Heating Oil and Gasoline	0.9	0.9	Gallons

Cash Flow Hedging Strategies

SWEPCo utilizes cash flow hedges on certain derivative transactions for the purchase-and-sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. SWEPCo does not hedge all

commodity price risk.

SWEPco utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. SWEPco also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. SWEPco does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for “Derivatives and Hedging” requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and other assumptions. In order to determine the relevant fair values of the derivative instruments, SWEPco applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract’s term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management’s estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for “Derivatives and Hedging,” SWEPco reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, SWEPco is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for SWEPco as of December 31, 2024 and 2023. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for SWEPco as of December 31, 2024 and 2023.

Location and Fair Value of Derivative Assets and Liabilities Recognized in the Balance Sheet

The following tables represent the gross fair value of SWEPco’s derivative activity on the balance sheets.

Balance Sheet Location	December 31, 2024		
	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	\$ 19.1	\$ (1.0)	\$ 18.1
Long-Term Portion of Derivative Instrument Assets	—	—	—
Derivative Instrument Liabilities	3.4	(1.1)	2.3
Long-Term Portion of Derivative Instrument Liabilities	—	—	—

Balance Sheet Location	December 31, 2023		
	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	\$ 12.5	\$ (0.9)	\$ 11.6
Long-Term Portion of Derivative Instrument Assets	0.5	(0.5)	—
Derivative Instrument Liabilities	16.6	(1.0)	15.6
Long-Term Portion of Derivative Instrument Liabilities	1.7	(0.5)	1.2

(a) Derivative instruments within these categories are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for “Derivatives and Hedging.”

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for “Derivatives and Hedging.”

(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts:

Location of Gain (Loss)	Amount of Gain (Loss) Recognized on Risk Management Contracts	
	Years Ended December 31,	
	2024	2023
	(in millions)	
Operation Expenses	\$ (0.1)	\$ —
Maintenance Expenses	—	(0.2)
Other Regulatory Assets (a)	14.2	(15.5)
Other Regulatory Liabilities (a)	95.0	70.7
Total Gain on Risk Management Contracts	\$ 109.1	\$ 55.0

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for “Derivatives and Hedging.” Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for “Regulated Operations.”

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), SWEPCo initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2024 and 2023, SWEPCo did not apply cash flow hedging to outstanding power derivatives.

SWEPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-term Debt on the statements of income in those periods in which hedged interest payments occur. During the year ended 2024, SWEPCo did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2023, SWEPCo applied cash flow hedging to outstanding interest rate derivatives.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Credit-Risk-Related Contingent Features

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. SWEPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. SWEPCo had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2024 and 2023.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by SWEPCo under any of their outstanding debt of at least \$50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. SWEPCo's derivative contracts with cross-acceleration provisions outstanding as of December 31, 2024 and 2023 were immaterial.

Cross-Default Triggers

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is \$50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. SWEPCo had derivative contracts with cross-default provisions in a net liability position of \$2 million and no cash collateral posted as of December 31, 2024. SWEPCo had derivative contracts with cross-default provisions in a net liability position of \$15 million and no cash collateral posted as of December 31, 2023. If a cross-default provision would have been triggered, settlement at fair value would have been required.

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

		December 31,			
		2024		2023	
Book Value	Fair Value	Book Value	Fair Value	Book Value	Fair Value
(in millions)					
\$	3,669.3	\$	3,183.1	\$	3,668.9
				\$	3,209.7

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, SWEPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

	December 31, 2024									
	Level 1	Level 2	Level 3	Other	Total					
(in millions)										
Assets:										
Special Deposits	\$	3.4	\$	—	\$	—	\$	—	\$	3.4

Derivative Instrument Assets

Risk Management Commodity Contracts (a)	—	1.0	18.1	(1.0)	18.1
Total Assets	<u>\$ 3.4</u>	<u>\$ 1.0</u>	<u>\$ 18.1</u>	<u>\$ 1.0</u>	<u>\$ 23.5</u>
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	\$ —	\$ 2.8	\$ 0.6	\$ (1.1)	\$ 2.3
December 31, 2023					
(in millions)					
Assets:	Level 1	Level 2	Level 3	Other	Total
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)	\$ —	\$ 0.5	\$ 12.0	\$ (0.9)	\$ 11.6
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	\$ —	\$ 15.7	\$ 0.9	\$ (1.0)	\$ 15.6

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging." The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2024	Derivative Instrument Assets (Liabilities) (in millions)
Balance as of December 31, 2023	\$ 11.1
Realized Gain Included in Net Income (or Changes in Net Assets) (a) (b)	23.6
Settlements	(36.0)
Transfers out of Level 3 (c)	0.5
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	18.3
Balance as of December 31, 2024	<u>\$ 17.5</u>
Year Ended December 31, 2023	Derivative Instrument Assets (Liabilities) (in millions)
Balance as of December 31, 2022	\$ 14.2
Realized Gain Included in Net Income (or Changes in Net Assets) (a) (b)	20.0
Settlements	(34.2)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	11.1
Balance as of December 31, 2023	<u>\$ 11.1</u>

- (a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs December 31, 2024							
Type of Input	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range		Weighted Average (c)
	Assets	Liabilities			Low	High	
(in millions)							
FTRs	\$ 18.1	\$ 0.6	Discounted Cash Flow	Forward Market Price (a)	\$ (29.48)	\$ 10.54	\$ (3.88)
December 31, 2023							
Type of Input	Fair Value		Valuation Technique	Significant Unobservable Input	Input/Range		Weighted Average (c)
	Assets	Liabilities			Low	High	
(in millions)							
Natural Gas Contracts	\$ —	\$ 0.5	Discounted Cash Flow	Forward Market Price (b)	\$ 3.11	\$ 3.11	\$ 3.11
FTRs	12.0	0.4	Discounted Cash Flow	Forward Market Price (a)	(25.45)	4.80	(4.33)
Total	<u>\$ 12.0</u>	<u>\$ 0.9</u>					

- (a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.
(c) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Natural Gas Contracts and FTRs as of December 31, 2024 and 2023:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

Income Tax Benefit

The details of SWEPCo's Income Tax Benefit as reported are as follows:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	\$ (107.4)	\$ (72.6)
Deferred	40.4	56.5
Total	<u>(67.0)</u>	<u>(16.1)</u>
Charged (Credited) to Non-Operating Income, Net:		
Current	(3.8)	(18.8)
Deferred	—	0.6
Total	<u>(3.8)</u>	<u>(18.2)</u>
Income Tax Benefit	<u>\$ (70.8)</u>	<u>\$ (34.3)</u>

The following is a reconciliation between the federal income taxes computed by multiplying pretax income (loss) by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Net Income	\$ 321.2	\$ 220.3
Less: Equity Earnings – Dolet Hills	(1.5)	(1.5)
Income Tax Benefit	(70.8)	(34.3)
Pretax Income	<u>\$ 248.9</u>	<u>\$ 184.5</u>
Income Taxes on Pretax Income at Statutory Rate (21%)	\$ 52.3	\$ 38.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	2.1	2.1
Investment Tax Credit Amortization	(0.1)	(0.2)
Production Tax Credits	(70.7)	(67.1)
State and Local Income Taxes, Net	10.6	(4.0)
AFUDC Equity	(2.8)	(2.4)
Tax Reform Excess ADIT Reversal	(4.0)	(12.6)
Remeasurement of Excess ADIT	(32.4)	—
Federal Return to Provision	—	1.0
Other	(25.8)	10.2
Income Tax Benefit	<u>\$ (70.8)</u>	<u>\$ (34.3)</u>
Effective Income Tax Rate	(28.5)%	(18.6)%

See Note 19 - Resubmission Disclosure – Income Taxes for additional information on the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities.

Net Deferred Tax Liability

The following table shows elements of SWEPCo's net deferred tax liability and significant temporary differences. Amounts presented for 2023 were recast to allocate "Deferred State Income Taxes", and other miscellaneous temporary differences, amongst other categories to substantively reflect the elements of the net deferred tax liability.

	December 31,	
	2024	2023
	(in millions)	
Deferred Tax Assets	\$ 259.7	\$ 412.9
Deferred Tax Liabilities	(1,533.9)	(1,594.6)
Net Deferred Tax Liabilities	<u>\$ (1,274.2)</u>	<u>\$ (1,181.7)</u>
Property Related Temporary Differences	\$ (1,353.1)	\$ (1,306.0)
Amounts Due to Customers for Future Income Taxes	90.2	142.5
Securitized Assets	(81.1)	2.8
Regulatory Assets	(87.0)	(146.9)
Net Operating Loss Carryforward	36.5	47.5
Tax Credit Carryforward	31.7	68.6
Operating Lease Liability	35.7	33.3
Investment in Partnership	(1.5)	(1.5)
Valuation Allowance	—	(1.8)

All Other, Net	54.4	(20.2)
Net Deferred Tax Liabilities	<u>\$ (1,274.2)</u>	<u>\$ (1,181.7)</u>

Federal and State Income Tax Audit Status

SWEPco and other AEP subsidiaries are not currently under IRS audit and the statute of limitations (SOL) for the IRS to examine SWEPco and other AEP subsidiaries originally filed federal return has expired for tax years prior to 2017. SWEPco and other AEP subsidiaries agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the Congressional Joint Committee on Taxation (JCT) adequate time to complete its review of the now closed IRS audit. Following JCT's approval, SWEPco and other AEP subsidiaries received IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that SWEPco and other AEP subsidiaries hold an interest in.

SWEPco and other AEP subsidiaries file income tax returns in various state and local jurisdictions. SWEPco and other AEP subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Net Income Tax Operating Loss Carryforward

As of December 31, 2024, SWEPco has state net income tax operating loss carryforwards (NOLC) of \$909 million. Net of tax, the NOLC amounts to \$36.1 million of future tax benefit. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires.

State/Municipality	State Net Income Tax Operating Loss Carryforward		Years of Expiration
	(in millions)		
Arkansas	\$	273.5	2031 - 2034
Louisiana		635.5	N/A (a)

(a) NOL's generated beginning in 2001 can be carried forward indefinitely, effective January 1, 2022.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2019 and 2021 resulted in unused federal and state income tax credits. As of December 31, 2024, SWEPco has federal tax credit carryforwards in the amount of \$31.7 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041 and state tax credits will remain available indefinitely.

Valuation Allowance

SWEPco assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that it is more-likely-than-not that SWEPco will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether SWEPco has a history of recognizing income, future reversals of existing temporary differences and tax planning strategies.

13. LEASES

SWEPco leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. SWEPco does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain SWEPco will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, SWEPco measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expense and Maintenance Expense in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs were as follows:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Operating Lease Cost	\$ 17.4	\$ 17.2
Finance Lease Cost:		
Amortization of Right-of-Use Assets	13.0	6.5
Interest on Lease Liabilities	1.6	1.4
Total Lease Rental Costs (a)	<u>\$ 32.0</u>	<u>\$ 25.1</u>

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below:

	December 31,	
	2024	2023
	(in millions)	
Weighted-Average Remaining Lease Term (years):		
Operating Leases	22.02	22.60
Finance Leases	6.14	4.78
Weighted-Average Discount Rate:		
Operating Leases	3.59 %	3.52 %
Finance Leases	5.73 %	3.22 %

	Years Ended December 31,	
	2024	2023
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	\$ 16.5	\$ 16.2
Operating Cash Flows from Finance Leases	15.7	7.1
Non-cash Acquisitions Under Operating Leases	\$ 26.9	\$ 14.3

The following tables show property, plant and equipment under finance leases, operating leases and related obligations recorded on SWEPCo's balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	December 31,	
	2024	2023
	(in millions)	
Property, Plant and Equipment Under Finance Leases:		
Utility Plant (a)	\$ 18.5	\$ 29.0
Obligations Under Finance Leases:		
Noncurrent	\$ 14.8	\$ 18.7
Current	3.7	11.3
Total Obligations Under Finance Leases	\$ 18.5	\$ 30.0

(a) Includes \$13 million and \$28 million of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

	December 31,	
	2024	2023
	(in millions)	
Property, Plant and Equipment Under Operating Leases:		
Utility Plant (a)	\$ 140.7	\$ 125.6
Obligations Under Operating Leases:		
Noncurrent	\$ 137.5	\$ 122.2
Current	7.9	8.7
Total Obligations Under Operating Leases	\$ 145.4	\$ 130.9

(a) Includes \$40 million and \$32 million of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

Future minimum lease payments consisted of the following as of December 31, 2024:

	Finance Leases Operating Leases	
	(in millions)	
2025	\$ 4.6	\$ 17.3
2026	4.0	15.5
2027	3.3	14.1
2028	2.7	12.1
2029	2.4	9.0
After 2029	5.1	178.1
Total Future Minimum Lease Payments	22.1	246.1
Less: Imputed Interest	3.6	100.7
Estimated Present Value of Future Minimum Lease Payments	\$ 18.5	\$ 145.4

Master Lease Agreements

SWEPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, SWEPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2024, the maximum potential loss by SWEPCo for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was \$5 million.

Lessor Activity

SWEPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2024 and December 31, 2023, respectively.

14. VOLUNTARY SEVERANCE PROGRAM

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP's workforce. Approximately 7,400 of AEP's 16,800 employees were eligible to participate in the program. Approximately 1,000 employees chose to take the voluntary severance package and substantially all terminated employment in July 2024. The severance program provides two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Certain positions impacted by the voluntary severance program have been and will continue to be refilled to maintain safe, effective and efficient operations. Net savings from the program will help offset increasing operating expenses and high interest costs in order to keep electricity costs affordable for customers.

SWEPco recorded a \$17 million charge to expense in the second quarter of 2024 related to this voluntary severance program. As of December 31, 2024, the remaining balance to be paid was \$1 million.

These expenses were primarily included in Operating Expenses on the statements of income and Miscellaneous Current and Accrued Liabilities on the balance sheets. Settlement accounting was triggered for the qualified pension plan in November 2024 under the accounting guidance for "Compensation - Retirement Benefits". A settlement charge of \$13 million was recorded. SWEPco will seek recovery for the expenses. See Note 8 - Benefit Plans for additional information associated with the plan.

15. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average	Interest Rate Ranges as of		Outstanding as of	
		Interest Rate as of	December 31,		December 31,	
	2026-2051	December 31, 2024	2024	2023	2024	2023
Senior Unsecured Notes		3.73%	1.65%-6.20%	1.65%-6.20%	\$ 3,675.0	\$ 3,675.0
Unamortized Discount, Net					(5.7)	(6.1)
Total Long-term Debt Outstanding					\$ 3,669.3	\$ 3,668.9

As of December 31, 2024, outstanding long-term debt was payable as follows:

	(in millions)
2025	\$ —
2026	900.0
2027	—
2028	575.0
2029	—
After 2029	2,200.0
Principal Amount	3,675.0
Unamortized Discount, Net	(5.7)
Total Long-term Debt	\$ 3,669.3

Dividend Restrictions

SWEPco pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of SWEPco to transfer funds to Parent in the form of dividends.

All of the dividends declared by SWEPco are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings.

SWEPco has credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for SWEPco is through the credit agreements. As of December 31, 2024, the maximum amount of restricted net assets of SWEPco that may not be distributed to the Parent in the form of a loan, advance or dividend was \$1.9 billion.

The credit agreement covenant restrictions can limit the ability of SWEPco to pay dividends out of retained earnings. As of December 31, 2024, the amount of any such restrictions was \$367 million.

Corporate Borrowing Program

SWEPco uses a corporate borrowing program to meet its short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2024 and 2023 are included in Notes Payable to Associated Companies on SWEPco's balance sheets. SWEPco's money pool activity and corresponding authorized borrowing limits are described in the following table:

Years ended	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
December 31,						
	(in millions)					
2024	\$ 362.2	\$ 59.3	\$ 249.5	\$ 57.3	\$ 275.0	\$ 750.0
2023	401.6	25.8	150.7	16.5	88.7	750.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years ended	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
December 31,						
2024	5.79 %	4.74 %	4.79 %	4.77 %	5.41 %	4.78 %
2023	5.79 %	4.66 %	5.81 %	5.58 %	5.34 %	5.72 %

Interest expense and interest income related to the Utility Money Pool financing relationship are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively.

on the statements of income. The interest expense related to the corporate borrowing programs were \$14 million and \$8 million for the years ended December 31, 2024 and 2023, respectively. The interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2024 and 2023, respectively.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, SWEPCo sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit and is charged a fee based on AEP Credit’s financing costs, administrative costs and uncollectible accounts experience for SWEPCo’s receivables. The costs of customer accounts receivable sold are reported in Other Deductions on SWEPCo’s statements of income. SWEPCo manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for SWEPCo and retains the remainder.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2024 and 2023 were \$154 million and \$168 million, respectively. The fees paid to AEP Credit for customer accounts receivable sold were \$18 million and \$19 million for the years ended December 31, 2024 and 2023, respectively.

The proceeds on the sale of receivables to AEP Credit were \$1.8 billion and \$1.9 billion for the years ended December 31, 2024 and 2023, respectively.

16. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “Income Taxes and Investment and Production Tax Credits” section of Note 1 in addition to “Corporate Borrowing Program” and “Securitized Accounts Receivables – AEP Credit” sections of Note 15.

Intercompany Billings

SWEPCo performs certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Operating Agreement

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies’ respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

Sales and Purchases of Property

SWEPCo had affiliated sales and purchases of electric property individually amounting to \$100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2024 and 2023 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP’s 11-state service area. Charitable contributions to the AEP Foundation were not made in 2024 or 2023.

Other Related Party Contributions

For the year ended December 31, 2023, AEP made contributions of \$0.1 million to Clean Affordable Reliable Coalition (CARE), a 501(c)(6) organization established to encourage communication, discussion and concerted action related to tax policy associated with clean, affordable and reliable power initiatives. These contributions were made in the ordinary course of business. AEP was a member of CARE and provided the organization its primary financial support. In addition, an employee of AEP served as a board member of the organization during 2023. AEP management has determined these contributions are Related Party transactions under ASC 850 based on AEP’s ability to significantly influence the management and operating policies of CARE. SWEPCo made no contributions to CARE in 2024.

Beginning in August 2024, an officer of AEP also served as a member of the board of directors of a company that is a vendor of SWEPCo. From August 2024 through December 2024, SWEPCo purchased \$1.2 million of distribution and transmission infrastructure services from the related party vendor in the ordinary course of business.

Transmission Service Charges

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. Under the TCA, AEPSC is responsible for monitoring the reliability of their transmission systems and administering the OATT. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.

SWEPCo recorded the net transmission service charges discussed above of \$65 million and \$49 million, for the years ended December 31, 2024 and 2023, respectively, in Operation Expense on the statements of income. Refer to the Affiliated Revenues section below for amounts related to these transactions.

Affiliated Revenues

The following table shows the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2024 and 2023:

Related Party Revenues	Years Ended December 31,	
	2024	2023
	(in millions)	
Transmission Revenues	\$ 60.6	\$ 45.3
Other Revenues	1.5	1.5
Total Affiliated Revenues	\$ 62.1	\$ 46.8

17. PROPERTY, PLANT AND EQUIPMENT

Depreciation

SWEPCo provides for depreciation of Utility Plant, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates by functional class:

Year	Steam	Other Generation	Transmission	Distribution	General
(in percentages)					

2024	3.3 %	5.2 %	2.2 %	2.9 %	6.7 %
2023	3.2 %	2.1 %	2.2 %	2.9 %	8.5 %

The composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, AEP evaluated the applicability of the rule to current and former plant sites and SWEPCo incurred ARO liabilities of \$24 million based on initial cost estimates. See the "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.

The following is a reconciliation of the 2024 and 2023 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO at December 31,
(in millions)						
2024	\$ 148.0	\$ 8.4	\$ 30.2	\$ (26.5)	\$ 23.0	\$ 183.1 (b)(c)(d)(e)
2023	\$ 159.0	\$ 7.8	\$ 1.5	\$ (23.2)	\$ 2.9	\$ 148.0 (b)(c)(d)(e)

- (a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to Sabine and DHLIC.
(d) Includes ARO related to asbestos removal.
(e) Includes ARO related to renewables.

Jointly-owned Electric Facilities

SWEPCo has electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. SWEPCo's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

Registrant's Share as of December 31, 2024					
Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation	
(in millions)					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	\$ 404.1	\$ 3.4	\$ 188.8
Turk Generating Plant (a)	Coal	73.3 %	1,517.0	1.2	350.2
North Central Wind Energy Facilities (b)(c)	Wind	54.5 %	1,093.5	1.2	98.1
Total			\$ 3,014.6	\$ 5.8	\$ 637.1

Registrant's Share as of December 31, 2023					
Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation	
(in millions)					
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	\$ 402.8	\$ 1.6	\$ 167.5
Turk Generating Plant (a)	Coal	73.3 %	1,504.0	10.1	323.3
North Central Wind Energy Facilities (b)(c)	Wind	54.5 %	1,086.3	2.9	67.9
Total			\$ 2,993.1	\$ 14.6	\$ 558.7

- (a) Operated by SWEPCo.
(b) Operated by PSO.
(c) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively.

18. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for SWEPCo:

	Years Ended December 31,	
	2024	2023
(in millions)		
Retail Revenues:		
Residential Revenues	\$ 682.1	\$ 746.0
Commercial Revenues	513.9	558.9
Industrial Revenues	318.3	358.9
Other Retail Revenues	9.2	10.1
Total Retail Revenues	1,523.5	1,673.9
Wholesale Revenues:		
Generation Revenues	193.4	191.0
Transmission Revenues (a)	172.1	150.8
Total Wholesale Revenues	365.5	341.8
Other Revenues from Contracts with Customers (a)	32.7	29.2

Total Revenues from Contracts with Customers	1,921.7	2,044.9
Other Revenues:		
Alternative Revenues	(7.0)	(9.4)
Other Revenues	4.4	(0.5)
Total Other Revenues	(2.6)	(9.9)
Total Operating Revenues	<u>\$ 1,919.1</u>	<u>\$ 2,035.0</u>

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

SWEPCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for “Revenue from Contracts with Customers” allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity’s measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. SWEPCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for SWEPCo are summarized as follows:

Retail Revenues

SWEPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer’s usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between SWEPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

SWEPCo has performance obligations to sell electricity to wholesale customers from generation assets in SPP. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer’s usage requirements.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

SWEPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated. The performance obligation to provide transmission services in SPP is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP.

SWEPCo collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year’s billings, allowing for over/under-recovery of the transmission owner’s ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for “Regulated Operations,” and are therefore presented as such in the disaggregated revenues table above.

PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. Affiliate revenues as a result of the TCA are reflected as Transmission Revenues in the disaggregated revenues table above.

Contract Assets and Liabilities

Contract assets are recognized when SWEPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. SWEPCo did not have any material contract assets as of December 31, 2024 and 2023.

When SWEPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. SWEPCo’s contract liabilities typically arise from services provided under joint use agreements for utility poles. SWEPCo did not have any material contract liabilities as of December 31, 2024 and 2023.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on SWEPCo’s balance sheets within the Customer Accounts Receivable line item. SWEPCo’s balances for receivables from contracts that are not recognized in accordance with the accounting guidance for “Revenue from Contracts with Customers” included in Customer Accounts Receivable were not material as of December 31, 2024 and 2023. See “Securitized Accounts Receivable - AEP Credit” section of Note 15 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on SWEPCo’s balance sheets were \$21 million and \$27 million, as of December 31, 2024 and 2023.

Contract Costs

Contract costs to obtain or fulfill a contract for SWEPCo are accounted for under the guidance for “Other Assets and Deferred Costs” and presented as a single asset and are neither bifurcated nor reclassified between current assets and deferred debits on the balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on the income statements. SWEPCo did not have material contract costs as of December 31, 2024 and 2023.

19. RESUBMISSION DISCLOSURE - INCOME TAXES

This Form 1 has been resubmitted to change the presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities as a result of the FERC's Order in Docket ER25-2364-000 issued in July 2025. The resubmission reclassifies \$114.4 million from FERC Account 411.2, Provision for Deferred Income Taxes-Cr (Line 56 on page 116) to Account 421, Miscellaneous Nonoperating Income (Line 39 on page 115) in SWEPCo's 2024 Income Statement. This reclassification does not impact net income, cash flows or the balance sheet for the year ended December 31, 2024. This change in presentation had no impact on the 2023 financial statements.

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(5,523,873)	1,311,905		(4,211,969)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(6,841,691)	451,388		(6,390,304)		
3	Preceding Quarter/Year to Date Changes in Fair Value				7,449,215	(264,013)		7,185,202		
4	Total (lines 2 and 3)				607,523	187,375		794,898	220,288,486	221,083,384
5	Balance of Account 219 at End of Preceding Quarter/Year				(4,916,350)	1,499,279		(3,417,070)		
6	Balance of Account 219 at Beginning of Current Year				(4,916,350)	1,499,279		(3,417,070)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(340,956)			(340,956)		
8	Current Quarter/Year to Date Changes in Fair Value				6,352,934	(275,298)		6,077,636		
9	Total (lines 7 and 8)				6,011,977	(275,298)		5,736,680	321,219,644	326,956,324
10	Balance of Account 219 at End of Current Quarter/Year				1,095,627	1,223,982		2,319,609		

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	10,767,318,703	10,767,318,703					
4	Property Under Capital Leases	159,172,195	159,172,195					
5	Plant Purchased or Sold	64,005	64,005					
6	Completed Construction not Classified	1,249,622,028	1,249,622,028					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	12,176,176,931	12,176,176,931					
9	Leased to Others							
10	Held for Future Use	2,183,899	2,183,899					
11	Construction Work in Progress	633,334,653	633,334,653.00					
12	Acquisition Adjustments	18,043,976	18,043,976					
13	Total Utility Plant (8 thru 12)	12,829,739,459	12,829,739,459					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	3,234,786,957	3,234,786,957					
15	Net Utility Plant (13 less 14)	9,594,952,502	9,594,952,502					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	3,118,709,295	3,118,709,295					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							

20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	98,034,099	98,034,099					
22	Total in Service (18 thru 21)	3,216,743,394	3,216,743,394					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	(413)	(413)					
29	Amortization							
30	Total Held for Future Use (28 & 29)	(413)	(413)					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	18,043,976	18,043,976					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,234,786,957	3,234,786,957					

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					

22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					
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Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
- For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
- For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	12,202					12,202
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	188,045,267	24,647,506	26,492,353			186,200,420
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	188,057,469	24,647,506	26,492,353			186,212,622
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	19,191,146	61,227			87,290	19,339,663
9	(311) Structures and Improvements	508,828,365	10,864,606	1,813,973			517,878,998
10	(312) Boiler Plant Equipment	2,104,324,310	23,496,398	10,222,643			2,117,598,065
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	648,872,310	20,587,814	7,803,465			661,656,659
13	(315) Accessory Electric Equipment	215,926,292	4,711,664	201,005			220,436,951
14	(316) Misc. Power Plant Equipment	185,182,876	6,943,741	2,543,091		89,705	189,673,231

15	(317) Asset Retirement Costs for Steam Production	54,895,828	44,533,472				99,429,300
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,737,221,127	111,198,922	22,584,177		176,995	3,826,012,867
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights	3,096,132		51,725		(87,290)	2,957,117
38	(341) Structures and Improvements	31,684,239	860,951	2,536			32,542,654

39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators	1,145,510,332	428,505,586	5,691,394			1,568,324,524
42	(345) Accessory Electric Equipment	11,502,265	535,048	96,463			11,940,850
43	(346) Misc. Power Plant Equipment	2,437,742	773,544	2			3,211,284
44	(347) Asset Retirement Costs for Other Production	24,544,414	6,440,282				30,984,696
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,218,775,124	437,115,411	5,842,120		(87,290)	1,649,961,125
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,955,996,251	548,314,333	28,426,297		89,705	5,475,973,992
47	3. Transmission Plant						
48	(350) Land and Land Rights	118,492,374	5,756,886				124,249,260
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	76,736,981	16,278,724	98,056			92,917,649
50	(353) Station Equipment	908,075,911	61,638,599	3,931,843			965,782,667
51	(354) Towers and Fixtures	36,072,351	1,644,642	841,900			36,875,093
52	(355) Poles and Fixtures	998,806,180	126,217,871	23,504,817			1,101,519,234
53	(356) Overhead Conductors and Devices	516,766,370	29,388,977	8,006,482			538,148,865
54	(357) Underground Conduit	14,562,592	3,105,708				17,668,300
55	(358) Underground Conductors and Devices	1,024,250	145,325				1,169,575
56	(359) Roads and Trails	131,947					131,947
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,670,668,956	244,176,732	36,383,098			2,878,462,590
59	4. Distribution Plant						
60	(360) Land and Land Rights	10,231,233	452,778	596		5,036	10,688,451
61	(361) Structures and Improvements	14,702,453	4,865,298	30,030			19,537,721
62	(362) Station Equipment	434,380,801	31,192,121	2,920,722			462,652,200
63	(363) Energy Storage Equipment – Distribution						

64	(364) Poles, Towers, and Fixtures	584,608,834	29,045,402	8,585,901			605,068,335
65	(365) Overhead Conductors and Devices	576,249,684	55,564,659	11,365,786			620,448,557
66	(366) Underground Conduit	91,349,923	6,495,772	100,504			97,745,191
67	(367) Underground Conductors and Devices	281,810,680	14,475,093	1,879,021			294,406,752
68	(368) Line Transformers	500,042,105	55,949,177	24,259,566			531,731,716
69	(369) Services	117,507,644	4,727,307	933,585			121,301,366
70	(370) Meters	116,092,853	28,495,291	2,498,001			142,090,143
71	(371) Installations on Customer Premises	51,795,132	4,454,943	2,955,768			53,294,307
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	55,521,425	5,931,855	3,041,726			58,411,554
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,834,292,767	241,649,696	58,571,206		5,036	3,017,376,293
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	8,352,581	1,862,827	103,463			10,111,945
87	(390) Structures and Improvements	118,198,167	106,008,652	894,823		(5,036)	223,306,960
88	(391) Office Furniture and Equipment	7,030,092	3,687,577	1,195,983			9,521,686

89	(392) Transportation Equipment	3,875,443	10,433				3,885,876
90	(393) Stores Equipment	3,551,261	58,396	1,218,869			2,390,788
91	(394) Tools, Shop and Garage Equipment	34,510,390	940,274	231,802			35,218,862
92	(395) Laboratory Equipment	5,117,545		110,553			5,006,992
93	(396) Power Operated Equipment	740,163	36				740,199
94	(397) Communication Equipment	111,453,125	36,057,570	777,055		(89,705)	146,643,935
95	(398) Miscellaneous Equipment	4,087,249	856,369	11,532			4,932,086
96	SUBTOTAL (Enter Total of lines 86 thru 95)	296,916,016	149,482,134	4,544,080		(94,741)	441,759,329
97	(399) Other Tangible Property	15,889,966					15,889,966
98	(399.1) Asset Retirement Costs for General Plant	1,265,939					1,265,939
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	314,071,921	149,482,134	4,544,080		(94,741)	458,915,234
100	TOTAL (Accounts 101 and 106)	10,963,087,364	1,208,270,401	154,417,034			12,016,940,731
101	(102) Electric Plant Purchased (See Instr. 8)	64,005					64,005
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,963,151,369	1,208,270,401	154,417,034			12,017,004,736

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
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41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

- Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
- For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Cardnell Road 138KV Substation (1062)	05/01/2009	12/31/2025	393,043.00
3	McCann Road 138/35kV Substation (1225)	06/01/2022	12/31/2025	649,660
4	Mt Pleasant Service Center (B0842)	04/01/2024	12/31/2026	592,700
5	Items under \$250,000			548,496.00
21	Other Property:			
22				
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46				
47	TOTAL			2,183,899

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	598MW SWEPCo Wagon Wheel	11,809,942.00
2	ADMS Imp DSN DNEX-SWP D	11,535,456.00
3	AMI SWEPCO Arkansas	10,684,737.00
4	Arsenal Hill Non-TX CI	24,567,390.00
5	Arsenal Hill TX CI	12,768,048.00
6	Ashdown to 12th St Non-TX CI	11,849,939.00
7	Ashdown to 12th St TX CI	(1,557,514.00)
8	Bann - Texarkana Ops Non-TX CI	4,912,581.00
9	Bann to Texarkana Ops TX CI	2,523,600.00
10	Beckville-Rock Hill non-TX CI	3,802,411.00
11	Beckville-Rock Hill TX CI	1,962,210.00
12	Bentonville Non-TX CI	1,560,522.00
13	Blanchard - N Market Non-TX CI	5,334,120.00
14	Blanchard to N Market TX CI	2,740,330.00
15	Bloomburg to Texark Non-TX CI	2,890,331.00
16	Bloomburg to Texark TX CI	1,480,586.00
17	Branch to N Magazine Non-TX CI	1,043,922.00
18	BROWNLEE RD: UPGRADE D-STATION	1,702,981.00
19	Bullock Non-TX Trans CI	3,790,515.00
20	Bullock Station D CI	7,067,467.00
21	Bullock Station TX Trans CI	1,945,850.00
22	CI 194	1,123,273.00
23	CI Eureka shadow	2,309,320.00
24	CIS-Common Deployment-SWP D	5,868,302.00
25	Corp Prgm Billing-SWEPCO T TX	1,328,833.00
26	Corp Prgm Billing-SWEPCO Tran	2,587,001.00
27	D/SW/Capital Blanket - SWEPCo	2,991,859.00
28	D/SW/Capital Blanket-SWEPCo-TX	1,641,979.00
29	DA Distribution Station - LA	1,149,283.00

30	DA Distribution Station - Ark	3,997,651.00
31	DA Distribution Station - TX	3,498,976.00
32	Daingerfield-Mt Pleasant TX CI	1,117,213.00
33	Daingerfield-MtPleas non-tx CI	2,174,705.00
34	Diana to Lone Star S Non-TX CI	10,001,717.00
35	Diana to Lone Star S TX CI	5,134,275.00
36	Dierks Non-TX CI	1,232,616.00
37	Dierks to Mena 111 CI	4,075,978.00
38	Dierks to Mena 194 CI	7,898,240.00
39	Dist Station Failures- SWEP TX	2,473,268.00
40	Ds-Septx-Ai Pole Replacement	3,091,665.00
41	Ed-Ci-Sepco-D Ast Imp	7,172,517.00
42	Ed-Ci-Sepco-D Cust Serv	6,608,324.00
43	Ed-Ci-Sepcotx-D Ast Imp	3,451,980.00
44	Ed-Ci-Sepcotx-D Cust Serv	1,121,155.00
45	Ed-Ci-Sepcotx-D Ppr	1,006,431.00
46	Ellerbe Rd - Fern St Non-TX CI	1,161,679.00
47	Eureka Springs - D-station	1,726,122.00
48	Eureka Springs 3 Terminal	4,502,244.00
49	Gilmer to Pittsburg Non-TX CI	4,035,992.00
50	Gilmer to Pittsburg TX CI	2,072,979.00
51	Grand Saline to Quit Non-TX CI	1,458,870.00
52	Gregg St - Add LTC and 3 bkrs	1,317,848.00
53	Harts Island D CI	1,006,001.00
54	Jefferson - Superior non-TX CI	4,902,861.00
55	JEFFERSON SHADOW	1,111,939.00
56	Jefferson to Superior TX CI	2,518,650.00
57	Knox Lee- S Texas E Non-TX CI	1,629,507.00
58	Lake Paul - W Child non-TX CI	21,371,586.00
59	Lake Pauline-Red Riv Non-TX CI	6,466,880.00
60	Lake Pauline-Red River TX CI	3,322,323.00
61	Lake Paul-W Child TX CI	10,979,666.00
62	LONE STAR SHELL ORD D-STATION	2,658,289.00
63	Longwood-EIDorado Non-TX CI	35,627,177.00
64	Longwood-EIDorado TX CI	18,973,069.00
65	Natchitoches Land Purchase	2,062,208.00
66	NGUCS/Radio SWEPKO Valley Impr	22,015,703.00

67	NW Texa to Patterson Non-TX CI	1,070,877.00
68	Petty D Station CI	2,133,842.00
69	Petty Station Non-TX CI	1,667,952.00
70	Pirkey 3&4 SCGT/Hallsville	21,056,692.00
71	Pirkey Non-TX CI	5,972,768.00
72	Pirkey to Scotsville non-tx CI	2,866,308.00
73	Pirkey to Scottsville TX CI	1,473,729.00
74	Pirkey TX CI	3,068,438.00
75	Prairie Grove POD Non-TX CI	1,372,499.00
76	Red Point Non-TX CI	13,522,088.00
77	Red Point TX CI	6,970,996.00
78	Rocking R D CI	1,156,588.00
79	Rocking R Solar Non-TX CI	2,403,245.00
80	Rocking R Solar TX CI	1,235,154.00
81	Sabine - D-Station	9,879,710.00
82	SABINE - T-Station-	1,418,281.00
83	Sawdust D CI	4,120,136.00
84	SEP-D Telecom	2,858,342.00
85	SEPT-D Telecom	1,086,518.00
86	SHADOW CI	3,274,460.00
87	SHADOW CI SWEPCO TX	1,444,719.00
88	Shreveport Service Center(New)	8,168,949.00
89	Ss-Ci-Sepco-D Gen Plt	1,534,775.00
90	Ss-Ci-SepcoTx-D Gen Plt	2,130,421.00
91	SW-D BlnktProj Under \$3M	4,993,945.00
92	SWEPCo Distr Pre Eng Parent 1	2,441,342.00
93	SWEPCo Distr Pre Eng Parent 2	5,798,949.00
94	SWEPCo Major Eq/Spares-Distr	7,578,253.00
95	SWEPCO North T TTMP 2024 CI	1,097,780.00
96	SWEPCO S Shadows 2024 TTMP CI	2,967,199.00
97	SWEPCO South T 2024 TTMP CI	2,762,125.00
98	SWEPCo Trans Pre Eng Parent 1	5,725,152.00
99	SWEPCo Trans Pre Eng Parent 2	1,722,867.00
100	SWEPCO Transmission 1	2,276,457.00
101	SWEPCO Transmission 2	6,377,805.00
102	SWEPCO Transmission CI	1,875,858.00
103	SWEPCo-D Spare/Major Equip CI	3,453,853.00

104	SWEPco-D-Tx Spare/Mjr Equip CI	1,401,742.00
105	SWEPCO-T Work HB4150	2,811,922.00
106	SW-T BlnktProj Under \$3M	12,691,749.00
107	SW-T BlnktProj Under\$3M-Shadow	6,531,864.00
108	T/SW/CapBlnkt-SW ShadowParent	1,952,949.00
109	T/SW/Capital Blanket - SWEPco	3,802,470.00
110	Tiller Non-TX CI	2,000,286.00
111	Tiller TX CI	1,028,402.00
112	Trans Station Failures- SWEPco	4,972,117.00
113	U2 GSU Spare Transformer	3,751,071.00
114	Wallace L-IPC Mansf Non-TX CI	3,769,253.00
115	Wallace L-IPC Mansf TX CI	1,936,357.00
116	Welsh U1&3 Gas Conversion	2,104,771.00
117	WS-CI-SEPCo-G PPB	25,384,566.00
118	Other Minor Projects Which is under 5% or \$1,000,000	49,842,484.00
43	Total	633,334,653.00

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	2,926,471,091	2,926,471,520	(429)	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	318,872,705	318,872,705		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,971,829	3,971,829		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	4,206,500	4,206,500		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	3,014,877	3,014,877		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	330,065,911	330,065,911		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(128,133,858)	(128,133,858)		
13	Cost of Removal	(50,775,117)	(50,775,117)		
14	Salvage (Credit)	7,761,022	7,761,022		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(171,147,953)	(171,147,953)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	33,319,833	33,319,817	16	
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,118,708,882	3,118,709,295	(413)	
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,282,088,407	1,282,088,407		

21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	139,423,600	139,423,600		
25	Transmission	668,419,079	668,419,079		
26	Distribution	906,744,250	906,744,663	(413)	
27	Regional Transmission and Market Operation				
28	General	122,033,546	122,033,546		
29	TOTAL (Enter Total of lines 20 thru 28)	3,118,708,882	3,118,709,295	(413)	

FOOTNOTE DATA

(a) Concept: OtherAccounts

Depr Exp classified to acct 1510001	\$ 897,170
Ash Pond Exp account 1823099	\$ (5,093)
Louisiana ARO asbestos depr exp	\$ 297,940
Louisiana ARO ash pond depr exp	\$1,541,348
Wind depr exp	\$283,512
Total	\$ 3,014,877

(b) Concept: CostOfRemovalOfPlant

Includes \$10,104,243 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes (\$4,421,710) of salvage in retirement work in progress (RWIP).

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
- If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Southwest Arkansas Utilities Corp. 100 shares, \$100 par value							
2	common stock	03/24/2028		10,000			10,000	
3	Dolet Hills Lignite Company (1)	06/01/2001						
4	Investment - Dolet Hills			8,087,121			8,087,121	
5	Dividends - Dolet Hills			(20,215,155)			(20,215,155)	
6	Equity in Undistributed Earnings - Dolet Hills			20,201,149	1,354,519	(1,402,757)	20,152,911	
7	Oxbow Lignite Company, LLC (2)	12/29/2009						
8	Investment - Oxbow Lignite			12,872,791			12,872,791	
9	Additional Investments (2016 Cash Infusion)			5,473,685			5,473,685	
10	Dividends - Oxbow Lignite			(16,445,204)		(792,551)	(17,237,755)	
11	Capital Contributions to Subs							
12	Mutual Energy SWEPCO, LLC	08/21/2015		3,028		1,693,201	1,696,229	
13	Investment - Mutual Energy			1,943,764			1,943,764	

14	Equity in Undistributed Earnings - Mutual Energy			258,101	110,698		368,799	
42	Total Cost of Account 123.1 \$		Total	12,189,280	1,465,217	(502,106)	13,152,390	

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	110,249,718	83,256,579	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	3,582,634	3,216,405	Electric
3	Residuals and Extracted Products (Account 153)		424	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	49,525,860	44,290,395	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	33,190,144	33,786,750	Electric
8	Transmission Plant (Estimated)	37,721	218,861	Electric
9	Distribution Plant (Estimated)	1,200,921	1,052,778	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	217,606	268,307	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	84,172,252	79,617,090	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1,700	2,643	
17				
18				
19				
20	TOTAL Materials and Supplies	198,004,604	166,090,075	

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FOOTNOTE DATA

(a) Concept: FuelStock
Formula Rate uses 13 month average.
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other: Includes Customer Accounts and Administrative and General Expenses (applies to both beginning and ending balances).
(c) Concept: PlantMaterialsAndOperatingSupplies
Formula Rate uses 13 month average. Production materials and supplies are identified by a query of the general ledger system.

20.1	Allowances Used										
21	Cost of Sales/Transfers:										
22	Surrenders										
23	Consent Decree Surrenders										
24	Unknown										
25	Other										
26											
27											
28	Total										
29	Balance-End of Year	905,886.00		94,108.00		72,752.00		72,752.00		1,931,250.00	3,076,748.00
30											
31	Sales:										
32	Net Sales Proceeds(Assoc. Co.)										
33	Net Sales Proceeds (Other)										
34	Gains		168								
35	Losses										
	Allowances Withheld (Acct 158.2)										
36	Balance-Beginning of Year										
37	Add: Withheld by EPA										
38	Deduct: Returned by EPA										
39	Cost of Sales										
40	Balance-End of Year										
41											
42	Sales										
43	Net Sales Proceeds (Assoc. Co.)										
44	Net Sales Proceeds (Other)										
45	Gains										
46	Losses										

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Luminant Generation Company LLC												
23	Surrenders												
24	Birchwood Power Partners, L.P.												
25	Wolverine Power Supply Cooperative, Inc.												
26	Allegheny Energy Supply Company, LLC												
27	Consent Decree Surrenders												
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)	3,547.00	299,810	3,757.00							7,304.00	299,810	
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
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41						
42						
43						
44						
45						
46						
47						
48						

49	TOTAL					
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Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	GEN-2018-088	844	186		
3	GEN-2018-106	214	186		
4	GEN-2019-065	824	186		
5	GEN-2022-038	357	186		
6	GEN-2022-088	2,793	186		
7	GEN-2022-089	93	186		
8	GEN-2022-093	272	186		
9	GEN-2022-108	357	186		
10	GEN-2022-111	9,428	186		
11	GEN-2022-139	623	186		
12	GEN-2022-239	93	186		
13	GEN-2022-240	93	186		
14	GEN-2022-241	93	186		
20	Total				
21	Generation Studies				
39	Total				
40	Grand Total				

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Estimated fuel disallowance.	(11,000,000)	22,000,000	0	11,000,000	
2	2021 Winter Storm carrying costs on unrecovered fuel costs related to the Arkansas portion of SWEPCO 2021 Winter Storm, Order 21 in APSC Docket 19-008-U		306,905	254,407,431		306,905
3	Advanced Metering System (AMS) Deployment Plan for SWEPCO TX - O/U and Carry Charges, Docket No. 52389	3,329,025	914,681	182,254,403,407,431	559,520	3,684,186
4	Amortize approved Arkansas COVID Expenses per over a 5 year period, APSC Docket No. 21-070-U, Amortization Period: 07/2022 - 2027	1,298,228		426	370,922	927,306
5	Arkansas retail share of the Dolet Hills Net Book Value regulatory asset, APSC Docket No. 21-070-U	18,172,050	472,923	506,108,411	5,375,835	13,269,138
6	Asset Retirement Obligation - Ash Ponds - SFAS 143	394,336		403,411	17,932	376,404
7	COVID-19 Deferred Expense	4,436,512	654,541	426,407	1,441,689	3,649,364
8	Defer TX Line Inspection Costs	1,910,051	1,103,398	571	238,745	2,774,704
9	Deferral of Fuel Underrecovery - Arkansas	34,251,940	17,408,539	254,440,442,444,557	37,590,395	14,070,084
10	Deferral of Fuel Underrecovery - Louisiana	1	16,223,821	182,254,440,442,444,557	14,546,239	1,677,583
11	Deferral of Fuel Underrecovery - Texas	36,113,374	31,777,499	254,440,442,444,557	67,890,873	
12	Deferred Arkansas Environmental Chemical Costs, Docket No. 14-080-U 2	743,299		502	743,299	
13	Deferred O&M Expenses related to City of Shreveport Sewer Work for recovery over 15 months, LPSC Docket No. U-32220 Approved Feb 2016, LPSC Docket No. U-34200, Amortization Period: 05/2017-2018	1,484,026	66,055	593,421	895,619	654,462

14	Deferred Storm Expense	150,322,718			150,322,718	
15	Disallowance of the Arkansas portion of the Dolet Hills Plant, APSC Docket No. 21-070-U	(828,845)	397,669	407		(431,176)
16	Disallowance of the Texas portion of the Dolet Hills Plant, PUCT Docket 51415	(9,967,745)	775,090	407		(9,192,655)
17	Dolet Hills Fuel-Deferred AR	4,774,885		182	4,092,759	682,126
18	Dolet Hills Fuel-Deferred LA	35,415,405	3,319,668	419, 557	17,039,148	21,695,925
19	Environmental CWIP	7,264,586		182, 512	866,616	6,397,970
20	Louisiana 2013 Formula Rate Plan (FRP) Excess Refunds	936,507				936,507
21	Reg Asset-Mattison	1,538,424	76,904	407	815,348	799,980
22	NOLC Reg Asset-Equity Carrying	(22,386,129)	21,525,722	254, 407, 431	26,099,836	(26,960,243)
23	NOLC Regulatory Assets	37,929,281	56,047,237	254, 407, 431		93,976,518
24	North Central Wind over/under recovery of the WFA Rider	20,221,146	9,809,957	403	30,031,103	
25	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	533,308		926	533,308	
26	SFAS 109 Deferred FIT	47,339,411	113,753,930	282	112,479,814	48,613,527
27	SFAS 109 Deferred SIT	238,579,938	28,360,227	283	69,666,623	197,273,542
28	SFAS No. 158 - Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	99,919,833	175,164,001	228, 129, 190, 219	191,639,271	83,444,563
29	Surcharge for the excess winter storm expenses for Arkansas, Louisiana, and Texas	101,877,828	1,447,757	440, 442, 444, 557, 419	30,648,231	72,677,354
30	SWEPSCO Arkansas bad debt expense under base rates, Docket No. 21-070-U	6,512,344	1,743,283	426, 254		8,255,627
31	Texas retail share of the Dolet Hills Net Book Value regulatory asset, PUCT Docket 51415	41,876,927	246,185	407, 108, 411	3,388,355	38,734,757
32	Texas retail share of the retired gas units: Lieberman U2, Lone Star U1, and Knox Lee U2-4 net book value regulatory asset, PUCT Docket 51415	2,377,595		407	1,222,368	1,155,227
33	Transmission Base Plan Funding FERC Formula Rates Under Recovery	(2)	29,269	0	29,267	
34	Underrecovered Environmental Adjustment Clause - Louisiana		682,244	509	610,126	72,118
35	Underrecovery of Energy Efficiency Program Expenses - Texas	779,715	3,607,430	254, 440, 442, 907	2,377,324	2,009,821
36	Unrealized Loss on Forward Commitments	15,387,990	2,105,880	175, 244, 254	16,312,706	1,181,164

37	Unrecov Fuel Cost 2021 Weather	151,363,625	16,825,646	440, 442, 444, 557, 419, 182	60,636,762.00	107,552,509
38	Various Rate Case Expenses and amortizations approved from State Commission Authorities	9,766,178	1,105,704	419, 928	2,226,813.00	8,645,069
39	Welsh Power Plant Unit 2 Asbestos ARO Texas Portion - to be amortized over 24 years, PUCT Docket No. 46449	425,533		407	35,716.00	389,817
40	Welsh Power Plant Unit 2 Texas Portion - Recovery of Retired Undepreciated Balance, PUCT Docket No. 46449	14,417,518		407	580,796.00	13,836,723
41	Welsh/Flint Creek Power Plants - Environmental Deferral - Amortized over 15 Years, LPSC Docket No. U-34200, Amortization Period: 05/2017 - 2032	8,904,930	574,818	403, 408, 431	1,643,410	7,836,338
42	Incremental Storm Cost Related to the 2023 Thunder Storm to the Catastrophe Reserve	53,376,329	70,008,475	924, 571, 593	73,993,839	49,390,965
43	Dolet LA Share Undeprec Bal	40,809,211	842,547	506, 108, 407	22,673,123	18,978,635
44	Pirkey LA Share Undeprec Bal	65,807,762	5,455,350	506, 108, 407	4,833,887	66,429,225
45	Pirkey AR Share Undeprec Bal	35,231,943	2,272,993	108	619,567	36,885,369
46	LA Storm Carrying Charges	(2,946,396)	8,500,995	431	5,554,599	
47	SWEPCO TX Fuel Mine Costs	80,850,910	745,847	419, 440, 442, 444	4,351,198	77,245,559
48	Trans BPF		4,563,555	254, 565	2,567,355	1,996,201
49	Louisiana AMS Regulatory Asset		19,229	928		19,229
50	LA AMS Def Equity Asset	9,938	151,262	254		161,200
51	Unrecovered TX Line Insp Cost		366,110		8,257	357,853
52	LA Storm Cost Securitization		223,533,154	254, 557	223,351,241	181,913
53	Mining Land AR Carrying Costs		35,072			35,072
54	Pirkey AR Carrying Costs		457,435			457,435
55	Pirkey AR Equity Carrying Cost			182	173,358	(173,358)
56	Mining Land AR Equity CC			182	13,291	(13,291)
57	Recoverable Bond Defeas Cost					
44	TOTAL	1,329,555,443	845,479,007		1,202,109,201	972,925,250

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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MISCELLANEOUS DEFERRED DEBITS (Account 18

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS
				Credits Account Charged (d)
1	Agency Fees - Factored Accounts Receivable	3,365,440	38,792,488	142/184/234/426
2	Associated Business Development Billings and Deferred Projects	1,759,560	76,896,484	107/108/143/151/154/163/183/184/186/232/234/236/242/502/506/508
3	Unamortized Credit Line Fees Amortization	830,459	1,094,733	234/431
4	Sabine Mine Preparation - Rusk County, TX - Amortization based on tons mined			
5	Deferred Expenses - Disposition of Fuel	88,084	136,903	152/183/501/506/528/530/535/539/547/548
6	Deferred Expense - Underrecovery of Transsource Missouri	89,490	15,023	565/146
7	Deferred Rate Case Expense	103,984	380,472	107/108/146/154/163/165/181/184/186/232/234/236/241/242/243
8	Deferred Leased Assets	109,083	1,465,894	107/108/142/146/154/184/186/232/234/235/236/237/426/580/583/584
9	Dolet Hills and Sabine Reclamation Advance	80,738,100	90,429,585	107/108/143/151/152/154/163/183/184/186/232/234/236/242/500
10	Deferred Lignite Lease			
11	Minor Items < \$100,000	78,550	496,164	107/108/131/142/146/163/184/185/186/232/234/235/236/242/253/408/426/566/580/582/583/584/585

12	Provision for refund related to overcollection of 2022 SPP revenue	28,604,144	32,786,798	229/253/431/456/565/146
47	Miscellaneous Work in Progress			
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)			
49	TOTAL	115,766,894		

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	TAX CREDIT C/F W DEF TAX		31,727,876
3	EXCESS ADFIT - PROTECTED.	138,660,473	86,997,207
4	DEFD TAX GAIN - SEC I REG ASSET		(66,946,952)
5	ACCRD BOOK ARO EXPENSE - SFAS 143	29,706,999	37,092,321
6	BOOK OPERATING LEASE	27,438,703	30,504,684
7	Other	11,024,630	9,008,180
8	TOTAL Electric (Enter Total of lines 2 thru 7)	206,830,805	128,383,316
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	206,055,079	131,310,852
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	412,885,884	259,694,168

Notes

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Formula Rate uses 13 month average.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non Utility Items - 190.2	(6,486)	1
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	204,754,687	131,602,093
Accu Def Income Taxes Pension-OCI	1,306,878	(291,242)
Total	206,055,079	131,310,852
 Line 18		
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :		
Balance at Beginning of Year		412,885,884
(Less) Amounts Debited to:		
(a) Account 410.1		(343,954,865)
(b) Account 410.2		—
(c) 1823/254/219/129/427		(16,552,256)
(Plus) Amounts Credited to:		
(a) Account 411.1		175,389,446
(b) Account 411.2		6,487
(c) 1823/254/219/129/427/421		31,919,472
Balance at End of Year		259,694,168
See Note 18 - Resubmission Disclosure - Income Taxes for additional information on the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities.		

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock (Account 201)	7,600,000	18.00		3,680	66,240				
7	Total	7,600,000			3,680	66,240				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 2025-11-05	Year/Period of Report End of: 2024/ Q4
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Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

- a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
- b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	680,000,000
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	60,000,000
4	Ending Balance Amount	740,000,000
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	2,106,937
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	2,106,937
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	810,040,072
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(2,456,111)
16	Ending Balance Amount	807,583,961
17	Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,549,690,898

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
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10		
11		
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14		
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19		
20		
21		
22	TOTAL	

17	Senior Unsecured Notes Series H, 6.20%		350,000,000		3,509,108		147,000	03/15/2010	03/15/2040	03/15/2010
18	^(a) Senior Unsecured - Series P, 5.30%		350,000,000		2,889,534		458,500	03/30/2023	04/01/2033	03/30/2023
19	Senior Unsecured Notes Series J, 3.90%		400,000,000		3,980,775		3,568,000	03/26/2015	04/01/2045	03/26/2015
20	Senior Unsecured Notes Series K, 2.75%		400,000,000		2,925,034		416,000	09/29/2016	10/01/2026	09/29/2016
21	Senior Unsecured Notes Series L, 3.85% FERC Authority ES17-43-000		450,000,000		4,656,209		958,500	01/22/2018	02/01/2048	01/22/2018
22	Senior Unsecured Notes Series M, 4.10% FERC Authority ES18-32-000		575,000,000		4,369,257			09/13/2018	09/15/2028	09/13/2018
23	Senior Unsecured - Series N, 1.65%		500,000,000		3,903,793		50,000	03/15/2021	03/15/2026	03/15/2021
24	Senior Unsecured - Series O, 3.25%		650,000,000		6,790,998		2,346,500	11/01/2021	11/01/2051	11/01/2021
25	Senior Unsecured Notes - Financial Hedges									
26	Subtotal									
33	TOTAL		3,675,000,000							

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FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
In March 2023, new Issuance for SWEPCO Series P Unsecured Notes 5.30% for \$350,000,000 with maturity date April 2033.

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	321,219,644
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	(73,373,416)

28	Show Computation of Tax:	
29		
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FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome	
	In (000's)
Net Income for the Year per Page 117	321,220
Federal Income Taxes	(84,264)
State Income Taxes	13,431
Pre-Tax Book Income	<u>250,387</u>
Allowance for Funds Used During Construction and Other Differences:	
Between Items Capitalized for Books and Expensed for Tax	(11,244)
Accrued Company-wide Incentive Plan	2,671
Book / Tax Unit of Property Adj	(103,522)
Capitalized Relocation Costs	(4,549)
Capitalized Software	13
Deferred Fuel Costs (Net)	54,618
Disallowed Costs - Turk Plan	1,203
Disallowed Costs - PUCT	(201)
Equity in Earnings of Subsidiary Companies	(1,465)
Excess Tax Vs Book Depreciation	(196,279)
Pension Expenses (Net)	680
Premium / Loss on Reacquired Debt (Net)	600
Provision for Revenue Refund	153,012
Regulatory Assets	10,463
Removal Costs	(44,077)
SFAS 106 - Post Retirement Benefit Expense Accrued / Funded (Net)	(3,299)
SFAS 112 - Post Employment Benefit Expense Accrued / Funded (Net)	113
Others	(181,717)
Taxable Income before State Taxes	(72,593)
State & Local Current Tax	780
Federal Taxable Income	<u>(73,373)</u>
Computation of Tax:	
FIT on Current Year Taxable Income @ 21%	(15,408)
Tax Credits	32,719
R and D Credit	240
Estimated Tax Currently Payable (a)	<u>(48,367)</u>
Adjustments of Prior Year's Accruals	6,089
Estimated Current Federal Income Taxes	<u><u>(42,278)</u></u>
a) Represents the allocation of estimated current year net operating tax income of American Electric Power Company, Inc.	
Instruction 2.	
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal Income Tax. The computation of actual 2024 System Federal income taxes will not be available until the consolidated Federal Income tax return is filed by October 2025. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the Consolidated Federal Income Tax Return is filed.	
See Note 18 - Resubmission Disclosure - Income Taxes for additional information on the change in presentation of the 2024 income tax benefit associated with remeasurement of certain Excess Deferred Income Tax regulatory liabilities.	

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. If the actual, or estimated amounts of such taxes are known, show the amounts in the accounts to which the taxed material was charged.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in the accounts in inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) taxes accrued and prepaid during the year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the tax year.
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot-note. Designate debit adjustments with a minus sign.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmission to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT YEAR
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)
1	Local Franchise	Local Tax	LA		2,226,858	10,685	9,768,818	9,764,942		2,215,317
2	Local Franchise	Local Tax	TX		1,714,978	0	8,765,734	8,767,193		1,713,519
3	Subtotal Local Tax				3,941,836	10,685	18,534,552	18,532,135		3,928,836
4	Pers Prop Leased	Property Tax	OK		0	0	0	0		0
5	Pers Prop Leased	Property Tax	TX		172,960	0	476,506	319,440		330,026
6	Real & Pers Prop	Property Tax	AR		18,244,706	0	18,587,156	17,773,097		19,058,765
7	Real & Pers Prop	Property Tax	LA		0	0	46,616,924	46,616,924		0
8	Real & Pers Prop	Property Tax	MO		0	0	33,433	33,433		0
9	Real & Pers Prop	Property Tax	OK		4,763,302	0	10,754,304	10,188,983		5,328,623
10	Real & Pers Prop	Property Tax	TX		20,769,022	0	18,755,314	22,897,197		16,627,139
11	Real & Pers Prop	Property Tax	WV		0	0	8,327	8,327		0
12	Real & Pers Prop	Property Tax	WY		0	0	2,555	2,555		0
13	Subtotal Property Tax				43,949,990	0	95,234,519	97,839,956		41,344,553
14	Unemployment Tax	Unemployment Tax	AR		2,052	0	6,383	5,635		2,800
15	Unemployment Tax	Unemployment Tax	LA		845	0	4,157	3,860		1,142

16	Unemployment Tax	Unemployment Tax	OK		0	0	(5)	(5)		0
17	Unemployment Tax	Unemployment Tax	TX		8,031	0	56,111	49,944		14,198
18	Unemployment Tax	Unemployment Tax	(blank)		16,407	0	65,505	60,370		21,542
19	Subtotal Unemployment Tax				27,335	0	132,151	119,804		39,682
20	Sales Tax	Sales And Use Tax	AR		0	960,200	0	498,400		0
21	Sales Tax	Sales And Use Tax	TX		0	0	17,142,614	17,142,614		0
22	Use Tax	Sales And Use Tax	AR		932,017	0	7,032,772	7,023,442		941,347
23	Use Tax	Sales And Use Tax	LA		544,602	0	8,499,184	8,203,338		840,448
24	Use Tax	Sales And Use Tax	OK		9,613	9,546	187,465	137,368		53,449
25	Use Tax	Sales And Use Tax	TX		333,228	0	6,159,507	5,977,658		515,077
26	Subtotal Sales And Use Tax				1,819,460	969,746	39,021,542	38,982,820		2,350,321
27	City Tax	Income Tax	MULTI		(902,128)	0	0	0		(902,128)
28	City Tax	Income Tax	OH		(37)	0	0	0		(37)
29	Federal Income	Income Tax			(21,083,309)	0	(21,923,325)	(13,872,677)		(29,133,957)
30	Federal Income	Income Tax	AR		(328,120)	0	0	0		(328,120)
31	State Income Tax	Income Tax	AR		126,486	0	412,618	0		539,104
32	State Income Tax	Income Tax	LA		(2,685,282)	0	907,631	0		(1,777,651)
33	State Income Tax	Income Tax	MULTI		(219,061)	0	0	0		(219,061)
34	State Income Tax	Income Tax	NE		(255,642)	0	0	84,000		(339,642)
35	State Income Tax	Income Tax	OH		3,072	0	0	0		3,072
36	State Income Tax	Income Tax	OK		(3,309)	0	3,821	0		512
37	State Income Tax	Income Tax	TX		1,136,464	0	417,313	0		1,553,777
38	State Income Tax FIN48	Income Tax	FIN48		0	0	0	0		0
39	Subtotal Income Tax				(24,210,866)	0	(20,181,942)	(13,788,677)		(30,604,131)
40	Excise Tax	Fuel Tax			0	0	32,462	32,462		0
41	Subtotal Fuel Tax				0	0	32,462	32,462		0
42	Federal Insurance Tax	Federal Insurance Tax	(blank)		633,040	0	12,337,991	12,267,368		703,663

43	Subtotal Federal Insurance Tax				633,040	0	12,337,991	12,267,368		703,663
44	State Franchise	Franchise Tax	DE		14,950	0	0	0		14,950
45	State Franchise	Franchise Tax	LA		1,114,344	0	5,237,855	6,153,204		198,995
46	State Franchise	Franchise Tax	OH		0	0	0	0		0
47	State Franchise	Franchise Tax	OK		0	0	20,100	20,100		0
48	State Franchise	Franchise Tax	TX		0	0	0	0		0
49	Subtotal Franchise Tax				1,129,294	0	5,257,955	6,173,304		213,945
50	Ohio CAT Tax	Other State Tax	OH		0	0	7	7		0
51	Subtotal Other State Tax				0	0	7	7		0
52	LA Occup Lic Fees	Other Taxes and Fees	LA		0	0	88,725	88,721		4
53	Gross Receipts Tax	Other Taxes and Fees	TX		0	0	7,968,111	7,968,111		0
54	Subtotal Other Taxes And Fees				0	0	8,056,836	8,056,832		4
40	TOTAL				27,290,089	980,431	158,426,073	168,216,011		17,976,873

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%				411.4					
5	10%	186,615	411.1		411.4	111,663		74,952	43 Years	
6	State DITC		411.1		411.4					
7	30%				411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)	186,615				111,663		74,952		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
47	OTHER TOTAL									
48	GRAND TOTAL	186,614						74,952		

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS	
			Contra Account (c)	
1	Insurance Liability - BREMCO	18,880	107/108/142/146/151/152/154/163/165/184/186/232/234/235/236/242/253/440/442/444/426/500/501/505/506/510/511/512/513/514/515	
2	^(a) Turk Power Plant Joint Ownership Deferred Credits	8,756,257	253/419	
3	^(b) Current Portion of Turk Power Plant Joint Ownership Deferred Credits	45,504	253	
4	Pole Attachments	1,830,495	172/173/454/589	
5	Customer Advance Receipts	7,491,778	142	
6	Contribution in Aid of Construction	1,536,862	107/108	
7	Pirkey Land Lease Obligations	2,122,071	107/108/143/146/151/154/163/165/183/184/186/232/234/500/501/502/505/506/510/511/512/513/514/515	
8	Quality of Service/Notice of Violation Penalty	606,781	242/426	
9	F.J. Doyle Salvage - Federal Super Fund Site	350,000	242/588	
10	Dolet Hills Def Lignite Lease Obligation	9,080,183	142/143/151/234/243/253	
11	Provision for refund related to overcollection of 2022 SPP revenue	29,922,151	229/234/242/449	
12	Minor Items	1,901,630	131/142/146/181/184/186/232/234/235/242/565	

47	TOTAL	63,662,592	
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Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits

Formula Rate Uses:
SPP Independent Power Producers System Upgrade Credits By Function
YEAR 2023

Description	Balance at Beg of Year	Transmission		Generation		Balance at End of Year
		Debit	Credit	Debit	Credit	
GENERATION						
Generation IPP Prepayment	24,241,915				(165,531)	24,076,384
Joint Owner IPP Credits	(8,756,257)			44,142	(780,201)	(9,492,316)
Current Portion of Joint Owner Credits	(45,503)			1,360		(44,143)
SWEPCO Share Generation IPP Prepayment	15,440,154	—	—	45,503	(945,732)	14,539,925
Transmission IPP Credits	(24,241,915)	—	165,531			(24,076,384)
TOTAL SWEPCo Company						
Total Line 3 & Line 6	(8,801,760)	—	165,531	42,503	(780,201)	(9,373,927)

(b) Concept: DescriptionOfOtherDeferredCredits

See Line 3 Footnote.

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	71,716,451	1,034,296	4,118,725							68,632,022
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	71,716,451	1,034,296	4,118,725							68,632,022
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109	(25,013,070) ^(a)					254		254	1,123,155	(23,889,915)

17	TOTAL (Acct 281) (Total of 8, 15 and 16)	46,703,381	1,034,296	4,118,725						1,123,155	44,742,107
18	Classification of TOTAL										
19	Federal Income Tax	46,703,381	1,034,296	4,118,725						1,123,155	44,742,107
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

Formula Rate uses 13 month average.

Description Page 272-273 Line 16	Balance at Beginning of The year	Balance End of Year
SFAS 109	(25,013,070)	(23,889,915)
Total Line 16	(25,013,070)	(23,889,915)

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS			
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits	
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)
1	Account 282									
2	Electric	1,484,914,277	160,881,945	227,798,656			37,151,395	190		1,
3	Gas									
4	Other (Specify)									
5	Total (Total of lines 2 thru 4)	1,484,914,277	160,881,945	227,798,656			37,151,395			1,
6	Other	(382,634,189) ^(a)				1823/254	5,218,403	1823/254	157,707,581	(:
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,102,280,088	160,881,945	227,798,656			42,369,798		157,707,581	1,
10	Classification of TOTAL									
11	Federal Income Tax	1,102,280,088	160,881,945	227,798,656			42,369,798		157,707,581	1,
12	State Income Tax									
13	Local Income Tax									

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Formula Rate uses 13 month average.

Line 6 Footnote

	Beg Bal	End Bal
Non-Utility	—	—
SFAS 109	(382,634,189)	(230,145,011)
Total Other - Line 6	(382,634,189)	(230,145,011)

15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	301,363,534 ^(a)					1823/254	162,202,304	1823/254	112,344,277	251
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	445,618,808 ^(b)	45,506,067	103,567,058				162,202,304		113,090,570	338
20	Classification of TOTAL										
21	Federal Income Tax	215,147,697	45,497,349	103,565,658				35,835,618		19,921,453	141
22	State Income Tax	230,471,111	8,718	1,400				126,366,686		93,169,117	197
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
SFAS 109	291,161,669	251,180,144
Hedge - Cash Flow	398,543	325,363
Provision Optimization	9,803,322	—
Total	\$ 301,363,534	\$ 251,505,507

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Formula Rate uses 13 month average.

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Arkansas Southwest Power Pool Transmission Cost Rider Over Recovery	3,083,829	565	4,438,883	1,355,054	
2	Deferred Overrecovery Fuel Costs - Louisiana	3,260,055	182, 557	3,260,055		
3	Louisiana EAC Over/Under Recovery and Interest	138,906		584,201	445,295	
4	Earnings Subject to Refund under State of Texas Restructuring Legislation - Public Utility Commission of Texas, PUCT Dockets No. 29938, 22276, and 37364, Amortization of 44 years beginning in May 2010	2,183,476	407	72,000		2,111,476
5	FAS 109 Deferred Federal Income Tax	585,261,454	182, 190, 236, 254, 255, 282, 283, 409, 410, 411, 281	213,244,201	8,323,315	380,340,568
6	Overrecovery of Energy Efficiency Program Expense Louisiana	5,242,691	908	3,554,338	7,442,652	9,131,005
7	Unrealized Gain/Loss on Forward Commitments		182	901,438	901,438	
8	Vegetation Management - Texas PUCT, Docket No.40443	615,128	593	5,099,547	4,484,419	
9	Over Recovered NCW-WFA			4,747,016	7,977,533	3,230,517
10	Advanced Metering System (AMS) deployment plan for SWEPCO LA in Docket No. U36169.	2,115,213	182, 254, 403	513,208	3,596,105	5,198,110
11	NOLC regulatory asset and regulatory liability consistent with the Order issued in U-35441 addressing the NOLC treatment per Regulatory Accounting.	15,543,152	182, 407, 431	11,125,596	12,988,607	17,406,163
12	Over Recovered Fuel Cost - TX		182	38,648	21,616,188	21,577,540
13	FAS 109 Flow Thru Deferred SIT		190.00	4,862.00	8,229.00	3,367.00
41	TOTAL	617,443,904.00		247,583,993.00	69,138,835.00	438,998,746.00

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	759,381,497	750,738,125	6,081,145	6,137,956	471,722	469,470
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	572,603,620	561,973,101	5,588,229	5,538,280	75,613	75,290
5	Large (or Ind.) (See Instr. 4)	357,130,599	361,585,769	5,157,052	5,147,435	6,632	6,723
6	(444) Public Street and Highway Lighting	14,637,259	9,646,884	68,834	70,983	563	576
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,703,752,975	1,683,943,879	16,895,260	16,894,653	554,530	552,059
11	(447) Sales for Resale	193,388,208	190,968,179	5,879,284	5,867,390		
12	TOTAL Sales of Electricity	1,897,141,183	1,874,912,058	22,774,544	22,762,043	554,530	552,059
13	(Less) (449.1) Provision for Rate Refunds	191,269,318	55,838,133				
14	TOTAL Revenues Before Prov. for Refunds	1,705,871,866	1,819,073,925	22,774,544	22,762,043	554,530	552,059
15	Other Operating Revenues						

16	(450) Forfeited Discounts	5,131,948	5,251,770				
17	(451) Miscellaneous Service Revenues	1,647,789	1,440,961				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	9,970,770	10,019,634				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	16,926,924	13,599,410				
22	(456.1) Revenues from Transmission of Electricity of Others	179,297,534	185,447,953				
23	(457.1) Regional Control Service Revenues	290,400	145,200				
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	213,265,366	215,904,928				
27	TOTAL Electric Operating Revenues	1,919,137,231	2,034,978,853				

Line 12, column (b) includes \$ (945,153) of unbilled revenues.

Line 12, column (d) includes (37,769,713) MWH relating to unbilled revenues

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
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42					
43					
44					
45					
46	TOTAL				290,400

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	^(a) Residential Service RS ARK	1,029,704	132,179,471	99,593	10,339	0.1284
2	Residential-Electric heating appliance ARK	118,551	13,944,262	8,503	13,942	0.1176
3	Master Metered Apartments ARK	934	96,411	8	124,564	0.1032
4	Lighting PL/AL/OL ARK	3,912	812,674	6,958	562	0.2077
5	Residential Service RS LA	2,805,525	367,732,154	207,238	13,538	0.1311
6	Residential Service RWH LA	1,082	134,811	72	15,091	0.1246
7	Master Metered Apartments LA	15,755	1,691,843	28	557,499	0.1074
8	Lighting PL/AL/OL	14,878	5,774,069	28,814	516	0.3881
9	Residential Service RS TX	2,089,589	277,355,049	156,256	13,373	0.1327
10	Deferred Fuel		(43,043,598)			
11				(54,540)		
12	Master Metered Apartments TX	9,817	911,054	24	409,028	0.0928
13	Lighting PL/AL TX	11,635	2,503,979	18,768	620	0.2152
41	TOTAL Billed Residential Sales	6,101,382	760,092,179	471,722	12,934	0.1246
42	TOTAL Unbilled Rev. (See Instr. 6)	(20,237)	(710,682)			
43	TOTAL	6,081,145	759,381,497	471,722	12,891	0.1249

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FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

The estimated additional revenue billed pursuant to the fuel adjustment clause is as follows:

	<u>Arkansas</u>	<u>Louisiana</u>	<u>Texas</u>
Residential	37,102,079.39	86,551,332.01	86,953,535.36
Commercial	40,980,459.93	67,624,799.61	82,832,110.30
Industrial	33,970,976.95	35,526,742.67	108,380,466.25
Public Street & Highway Lighting	254,985.91	1,108,029.59	1,014,683.88

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service GS	363,967	42,354,031	16,563	21,974	0.1164
2	Recreational Lighting ARK	4,122	364,886	95	43,237	0.0885
3	Lighting & Power Service LP LA	1,614,328	162,984,961	2,313	698,013	0.1010
4	Irrigation SVC LA					
5	Municipal Pumping MPS LA	80,598	7,190,107	590	136,626	0.0892
6	Municipal Service MS LA	19,534	3,004,910	1,038	18,814	0.1538
7	Lighting PL/AL/OL LA	17,864	4,580,521	11,904	1,501	0.2564
8	Lighting & Power Service LP ARK	819,858	80,395,610	1,393	588,555	0.0981
9	Large Lighting and Power Service LLP ARK	62,055	5,288,436	1	62,054,820	0.0852
10	Municipal Pumping Service MPS ARK	10,636	1,102,034	253	42,054	0.1036
11	Municipal Service MS ARK	4,656	547,453	416	11,206	0.1176
12	Lighting PL/AL/OL ARK	13,132	2,089,684	8,824	1,488	0.1591
13	Electric Sign Service ESS LA	520	107,267	304	1,712	0.2063
14	General Service GS LA	281,946	47,562,514	16,865	16,718	0.1687
15	General Lighting & Power GLP LA	205,284	28,426,172	4,512	45,493	0.1385
16	General Service GS TX	274,707	41,142,501	21,199	12,958	0.1498
17	Recreational Lighting Comm TX	5,940	678,426	157	37,915	0.1142
18	Lighting PL/AL TX	25,078	4,413,108	16,015	1,566	0.1760
19	Cotton Gin CG TX	2,886	373,065	6	480,930	0.1293
20	Lighting & Power Service LP TX	1,643,970	170,535,776	7,622	215,678	0.1037
21	Lighting & Power Service LLP TX	54,694	4,119,776	1	54,694,360	0.0753
22	Municipal Pumping MPS TX	62,868	5,462,871	607	103,530	0.0869
23	Municipal Service MS TX	26,747	2,889,930	1,580	16,930	0.1080

24	Deferred Fuel		(43,117,580)			
25	Duplicate Customers			(36,743)		
26	Lighting CSL TX	1,019	124,981	98	10,420	0.1227
41	TOTAL Billed Small or Commercial	5,596,409	572,621,440	75,613	74,014	0.1023
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(8,180)	(17,820)			
43	TOTAL Small or Commercial	5,588,229	572,603,620	75,613	73,906	0.1025

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service GS Ark	11,728	1,379,528	342	34,293	0.1176
2	Lighting & Power Service LP Ark	786,873	69,008,735	253	3,116,329	0.0877
3	Large Lighting & Power LLP Ark	172,839	10,448,129	1	172,839,440	0.0605
4	Pulp & Paper Mill P&PM Ark	108,218	6,573,725	1	108,217,845	0.0607
5	Lighting PL/AL/OL Ark	1,920	263,375	828	2,319	0.1372
6	General Power Service GPS LA	11,090	2,014,322	975	11,380	0.1816
7	General Lighting & Power GLP LA	33,614	4,441,003	673	49,959	0.1321
8	Lighting & Power Service LP LA	874,975	74,516,373	338	2,589,323	0.0852
9	Large Lighting & Power LLP LA	265,212	19,089,183	2	132,605,935	0.0720
10	Lighting PL/AL/OL	1,087	258,704	601	1,809	0.2380
11	General Service GS TX	12,434	1,936,023	1,387	8,957	0.1557
12	Lighting & Power Service LP TX	1,025,588	95,045,352	1,161	883,683	0.0927
13	Duplicate Customers			(2,715)		
14	Interruptible Power Service TX	36,592	2,268,263	2	17,564,160	0.0620
15	Large Lighting & Power Service LLP TX	908,835	59,517,384	6	151,472,575	0.0655
16	Large Lighting & Power Service LLP w/Bkup,Maint,AAS TX	479,197	25,533,056	3	179,698,782	0.0533
17	Metal Melting Service MMS TX	35,926	3,345,188	9	3,919,174	0.0931
18	Metal Melting Svc MMS Transmission TX					
19	Oilfield-Large Industrial OLI TX	397,295	29,342,002	1,479	268,579	0.0739
20	Lighting PL/AL TX	2,817	468,530	1,286	2,191	0.1663
21	Deferred Fuel		(48,085,731)			
41	TOTAL Billed Large (or Ind.) Sales	5,166,240	357,363,144	6,632	778,987	0.0692

42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(9,188)	(232,545)			
43	TOTAL Large (or Ind.)	5,157,052	357,130,599	6,632	777,650	0.0693

FERC FORM NO. 1 (ED. 12-95)

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Municipal Lighting ML ARK	7,921	1,998,033	199	39,722	0.2522
2	Municipal Lighting ML LA	35,799	4,467,821	181	198,149	0.1248
3	Deferred Fuel		4,444,086			
4	Municipal Lighting ML TX	25,278	3,711,425	183	138,445	0.1468
41	TOTAL Billed Public Street and Highway Lighting	68,998	14,621,365	563	122,554	0.2119
42	TOTAL Unbilled Rev. (See Instr. 6)	(164)	15,894			
43	TOTAL	68,834	14,637,259	563	122,334	0.2126

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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		191,269,318			

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	16,933,029	1,704,698,128	554,530	988,489	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(37,769)	(945,153)			
43	TOTAL - All Accounts	16,895,260	1,703,752,975	554,530	988,489	

2	(a) City of Bentonville, Arkansas (1)	RQ	126		128.9	126.1	737,492	22,755,949	21,730,206		44,486
3	City of Hope, Arkansas (1)	RQ	125		38.7	37.4	232,913	7,879,144	8,834,651		16,713
4	City of Minden, Louisiana (1)	RQ	128		27.5	26.2	135,376	4,691,690	4,449,277		9,140
5	City of Prescott, Arkansas (1)	RQ	127		24.7	19.8	67,571	1,845,491	2,367,362		4,213
6	Northeast Texas Electric	RQ	113		0.0	0.0	0				
7	Cooperative, Inc (NTEC) (1)		119				0	17,547,800	16,314,952		33,862
8	ETEC/ NTEC (1)	RQ	129		203.8	192.9	3,453,040	19,018,384	15,619,685		34,633
9	Rayburn Country Electric Coop, Inc(1,2)	RQ	111								
10	Tex-La Electric Reliability Council of Texas (ERCOT)	RQ	110								
11	Tex-La of Texas Elec. Coop. of Texas, Inc	RQ	120								
12	Corporation (AEPSC) (3)	OS	228								
13	AEPSC (3,8)	OS	228								
14	AEPSC (3,4)	OS	228							(954)	
15	Electric Reliability Council of Texas										
16	(ERCOT) (6,8)	OS	NA								
17	Oklahoma Gas & Electric	OS	NA								
18	Southwest Power Pool (SPP) (7)	OS	NA				854,298		28,898,063	7,545,989	36,440
19	SPP Merchant Sales (5)	SF	NA				398,594		13,890,519		13,890
15	Subtotal - RQ						4,626,392	56,190,658	53,001,181		109,191
16	Subtotal-Non-RQ						1,252,892	17,547,800	59,103,534	7,545,035	84,196
17	Total						5,879,284	73,738,458	112,104,715	7,545,035	193,387

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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Includes customer charge

(2) Wholesale transmission

(3) Respondent is an affiliated company of American Electric Power Service Corporation

(4) Bookout margins, net

(5) Merchant sale

(6) Net trading purchases & sales within the Electric Reliability Council of Texas (ERCOT)

(7) Net trading purchases & sales within the Southwest Power Pool (SPP)

(8) Realization System Integration Agreement Sharing

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	12,545,859	16,770,733
5	(501) Fuel	353,584,919	382,292,673
6	(502) Steam Expenses	18,719,300	20,989,507
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	10,271,735	9,973,816
10	(506) Miscellaneous Steam Power Expenses	15,035,510	10,551,927
11	(507) Rents		503
12	(509) Allowances	(131,314)	916,642
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	410,026,009	441,495,801
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,270,011	2,287,601
16	(511) Maintenance of Structures	6,025,337	5,554,603
17	(512) Maintenance of Boiler Plant	30,343,533	27,944,948
18	(513) Maintenance of Electric Plant	10,848,093	15,303,795
19	(514) Maintenance of Miscellaneous Steam Plant	5,193,265	5,727,915
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	54,680,239	56,818,862
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	464,706,247	498,314,663
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,675	(5,675)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	5,675	(5,675)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	5,675	(5,675)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,802,706	1,199,937
63	(547) Fuel	14,976,642	9,416,233
64	(548) Generation Expenses	354,502	258,761

64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	4,598,907	1,083,229
66	(550) Rents	5,972,421	5,640,579
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	27,705,178	17,598,739
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	209,846	80,724
71	(553) Maintenance of Generating and Electric Plant	7,908,785	9,096,447
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	106,646	49,727
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	8,225,277	9,226,898
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	35,930,455	26,825,637
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	211,665,852	221,555,627
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	643,030	1,185,783
78	(557) Other Expenses	37,495,637	49,313,894
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	249,804,518	272,055,304
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	750,446,896	797,189,929
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	12,015,040	12,092,288
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	916,029	712,609
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,037	1,516
88	(561.4) Scheduling, System Control and Dispatch Services	7,291,372	5,795,334
89	(561.5) Reliability, Planning and Standards Development	243,996	228,411
90	(561.6) Transmission Service Studies		(13)
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,147,898	1,147,621
93	(562) Station Expenses	1,240,868	1,042,278
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	57,816	65,311
95	(564) Underground Lines Expenses	80	

96	(565) Transmission of Electricity by Others	115,280,271	102,223,406
97	(566) Miscellaneous Transmission Expenses	5,096,330	2,610,810
98	(567) Rents	82,966	37,062
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	143,373,702	125,956,633
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	60,724	16,232
102	(569) Maintenance of Structures	47,755	53,640
103	(569.1) Maintenance of Computer Hardware	9,564	8,084
104	(569.2) Maintenance of Computer Software	1,021,670	833,143
105	(569.3) Maintenance of Communication Equipment	92,433	76,207
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,200,922	2,408,309
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	22,809,266	21,863,711
109	(572) Maintenance of Underground Lines	299	157
110	(573) Maintenance of Miscellaneous Transmission Plant	16,906	1,850
111	TOTAL Maintenance (Total of Lines 101 thru 110)	26,259,538	25,261,333
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	169,633,240	151,217,966
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	2,216,913	1,927,022
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	2,216,913	1,927,022
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		

130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	2,216,913	1,927,022
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,171,414	1,951,988
135	(581) Load Dispatching	68,633	89,709
136	(582) Station Expenses	1,077,846	1,237,425
137	(583) Overhead Line Expenses	(728,104)	1,313,333
138	(584) Underground Line Expenses	2,369,784	2,159,193
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	70,465	30,220
140	(586) Meter Expenses	3,002,799	3,528,872
141	(587) Customer Installations Expenses	800,703	780,877
142	(588) Miscellaneous Expenses	25,298,054	19,599,925
143	(589) Rents	1,218,572	1,029,116
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	35,350,166	31,720,658
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	192,354	134,960
147	(591) Maintenance of Structures	14,775	15,279
148	(592) Maintenance of Station Equipment	1,764,965	1,919,357
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	49,057,665	58,187,799
150	(594) Maintenance of Underground Lines	724,465	718,317
151	(595) Maintenance of Line Transformers	143,650	151,917
152	(596) Maintenance of Street Lighting and Signal Systems	160,690	86,150
153	(597) Maintenance of Meters	382,119	358,201
154	(598) Maintenance of Miscellaneous Distribution Plant	143,698	158,076
155	TOTAL Maintenance (Total of Lines 146 thru 154)	52,584,381	61,730,056
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	87,934,548	93,450,714
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	436,511	344,198
160	(902) Meter Reading Expenses	2,171,917	2,576,082
161	(903) Customer Records and Collection Expenses	17,741,220	17,802,775
162	(904) Uncollectible Accounts	71,677	(6,220)
163	(905) Miscellaneous Customer Accounts Expenses	85,308	83,774

164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	20,506,633	20,800,609
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	9,155,971	10,024,487
168	(908) Customer Assistance Expenses	17,901,408	14,834,769
169	(909) Informational and Instructional Expenses		1
170	(910) Miscellaneous Customer Service and Informational Expenses	3,479	16,993
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	27,060,858	24,876,250
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	104,109	109,706
176	(913) Advertising Expenses	381	
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	104,490	109,706
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	32,542,840	35,068,331
182	(921) Office Supplies and Expenses	691,298	3,169,865
183	(Less) (922) Administrative Expenses Transferred-Credit	7,874,278	7,175,093
184	(923) Outside Services Employed	13,692,655	4,004,437
185	(924) Property Insurance	10,016,422	7,653,598
186	(925) Injuries and Damages	6,911,491	4,423,839
187	(926) Employee Pensions and Benefits	15,196,166	1,774,157
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	9,822,614	8,165,441
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	333,517	411,315
192	(930.2) Miscellaneous General Expenses	6,106,828	1,818,497
193	(931) Rents	727,435	702,944
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	88,166,987	60,017,331
195	Maintenance		
196	(935) Maintenance of General Plant	7,632,026	6,644,237
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	95,799,013	66,661,568

198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,153,702,590	1,156,233,764
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6	Canadian Wind (3)	OS	NA				468,850				
7	ERCOT (5)	OS	NA								
8	Flat Ridge Wind Farm (3)	OS	NA				349,833				
9	Majestic Wind Farm (3)	OS	NA				674,808				
10	Southwest Power Pool (4)	OS	NA				6,809,954				
11	Snider Industries (2)	OS	NA				12,636				
12	VAISALA MONTHLY FORECASTING F	OS	NA								
13	Accounts Payable Accrual	OS	NA								
14	VAISALA - MAVERICK - 54.5 SWE	OS	NA								
15	VAISALA - SUNDANCE - 54.5 SWE	OS	NA								
15	TOTAL						8,316,081	0	0	0	11,34

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

C apacity

(3) Cogeneration

(4) Wind Energy

(5) Net Trading Purchases & Sales within Southwest Power Pool (SPP)

(6) Net Trading Purchases & Sales within ERCOT

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "w

- Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr for the quarter.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or trun any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Netw Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accour in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
- In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under whic
- Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where e
- Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in colum demand not stated on a megawatts basis and explain.
- Report in column (i) and (j) the total megawatthours received and delivered.
- In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all othe out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on b no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including th
- The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on f
- Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		C
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	
1	American Electric Power Service	Various	Various	OS	N/A	Various	Various				
2	(a) Corporation (1, 2, 3)										
3	Corporation (1, 2, 3, 6)										
4	Snider Industries Inc (5)	Various	Various	OS	N/A	Various	Various				
5	Southwest Power Pool (2, 3, 6, 7)	Various	Various	OS	196	Various	Various				
6	Southwest Power Pool (2, 3, 7)	Various	Various	OS	196	Various	Various				
35	TOTAL										

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Respondent is an affiliated company of American Electric Power Service Corporation

(2) Facility charge

(3) Southwest Power Pool base plan funding

(4) Southwest Power Pool ancillary service schedule 1

(5) Network Integrated Transmission Service (NITS)

(6) Prior Year

(7) Transmission service charge

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	American Electric Power Service Corporation (AEPSC) (1, 2, 3, 4, 5)	OS					68,075,844	68,075,844
2	Southwest Power Pool (3, 7)	OS					47,204,427	47,204,427
	TOTAL						115,280,271	115,280,271

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	186,134
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	281,506
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Associated Business Development	4,650,295
7	AEP Service Corporation and Other Affiliated	
8	Companies Billed to or from Respondent	921,069
9	Chamber of Commerce	37,746
10	Miscellaneous Minor items less than \$5,000	30,078
46	TOTAL	6,106,828

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			32,052,237		32,052,237
2	Steam Production Plant	120,856,568	3,417,011			124,273,579
3	Nuclear Production Plant					
4	Hydraulic Production Plant- Conventional					
5	Hydraulic Production Plant- Pumped Storage					
6	Other Production Plant	62,876,420	529,781			63,406,201
7	Transmission Plant	62,416,638				62,416,638
8	Distribution Plant	89,122,724				89,122,724
9	Regional Transmission and Market Operation					
10	General Plant	10,037,679	25,036			10,062,716
11	Common Plant-Electric					
12	TOTAL	345,310,030	3,971,829	32,052,237		381,334,096

B. Basis for Amortization Charges

Section A Line 1 Column D represents amortization of capitalized software development costs over a 5 year life and costs associated with the Oracle strategic partnership which are over a 10 year life.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM -- COAL/LIGNITE						

13	311 - Flint Creek	45,298	50 years	9%	3.79%		
14	311- Turk	303,009	50 years	2%	2.19%		
15	311 - Welsh	73,645	50 years	9%	3.71%		
16	312 - Flint Creek	300,914	50 years	9%	5.65%		
17	312 - Turk	993,255	50 years	2%	2.16%		
18	312 - Welsh	589,229	50 years	9%	4.67%		
19	314 - Flint Creek	17,947	50 years	9%	4.26%		
20	314 - Turk	239,786	50 years	2%	2.15%		
21	314 - Welsh	151,049	50 years	9%	4.09%		
22	315 - Flint Creek	12,301	50 years	9%	4.3%		
23	315 - Turk	90,868	50 years	2%	2.15%		
24	315 - Welsh	48,236	50 years	9%	5.06%		
25	316 - Flint Creek	7,396	50 years	9%	4.19%		
26	316 - Turk	51,435	50 years	2%	2.23%		
27	316 - Welsh	22,937	50 years	9%	4.08%		
28	TOTAL COAL/LIGNITE	2,947,305					
29	STEAM -- GAS/OIL						
30	311.3- ArsenalHillStall	53,038	35 years	6%	3.11%		
31	311.3-Arsenal Hill	7,321	65 years	31%	4%		
32	311.3 - Knox Lee	10,211	65 years	63%	3.86%		
33	311.3 - Lieberman	5,844	65 years	35%	6.65%		
34	311.3 - Wilkes	9,534	65 years	31%	3.3%		
35	312.3- ArsenalHillStall	89,514	35 years	6%	3.32%		
36	312.3 - Arsenal Hill	7,945	65 years	31%	4.19%		
37	312.3 - Knox Lee	32,068	65 years	63%	4.23%		
38	312.3 - Lieberman	19,826	65 years	35%	5.81%		
39	312.3 - Wilkes	60,429	65 years	31%	4.41%		
40	314.3- ArsenalHillStall	178,640	35 years	6%	3.81%		
41	314.3 - ArsenalHill	5,465	65 years	31%	3.91%		
42	314.3 - Knox Lee	15,715	65 years	63%	4.15%		
43	314.3 - Lieberman	10,879	65 years	35%	4.73%		
44	314.3 - Wilkes	42,144	65 years	31%	3.77%		
45	315.3- ArsenalHillStall	39,884	35 years	6%	3.09%		
46	315.3 - Arsenal Hill	1,301	65 years	31%	5.24%		

47	315.3 - Knox Lee	7,888	65 years	63%	4.68%		
48	315.3 - Lieberman	3,494	65 years	35%	6.86%		
49	315.3 - Wilkes	15,790	65 years	31%	4.96%		
50	316.3- ArsenalHillStall	84,025	35 years	6%	3.11%		
51	316.3 - Arsenal Hill	8,164	65 years	31%	7.28%		
52	316.3 - Knox Lee	2,255	65 years	63%	4.94%		
53	316.3 - Lieberman	2,330	65 years	35%	9.03%		
54	316.3 - Wilkes	10,722	65 years	31%	5.6%		
55	TOTAL GAS/OIL	724,426					
56	OTHER GENERATION						
57	341 - Mattison	31,367	45 years	7%	2.59%		
58	341 - Maverick	571	30 years		3.37%		
59	341 - Sundance	493	30 years		3.39%		
60	341 - Traverse	111	30 years		3.39%		
61	344 - Mattison	84,773	45 years	7%	2.58%		
62	344 - Maverick	220,353	30 years		3.37%		
63	344 - Sundance	158,466	30 years		3.39%		
64	344 - Traverse	687,307	30 years		3.39%		
65	345 - Mattison	11,769	45 years	7%	2.89%		
66	346 - Mattison	2,346	45 years	7%	2.92%		
67	346 - Maverick	361	30 years		3.37%		
68	346 - Sundance	429	30 years		3.39%		
69	346 - Traverse	75	30 years		3.39%		
70	TOTAL OTHER	1,198,421					
71	TRANSMISSION						
72	350 (Rights)	116,161	70 years		1.36%	R5	
73	352	87,199	70 years	7%	1.44%	R3.5	
74	353	924,498	68 years	9%	1.51%	S0	
75	353.16	31,797	68 years	9%	1.52%	S0	
76	354	35,566	65 years	18%	1.33%	L3	
77	355	1,054,156	46 years	64%	3.33%	S0.5	
78	356	454,414	70 years	53%	2.09%	R2	
79	356.16	66,825	70 years	53%	2.01%	R2	
80	357	16,273	50 years		2%	R1.5	
81	358.16	1,078	50 years		1.99%	R1.5	
82	359	132	65 years		1.07%	R4	

83	TOTAL TRANSMISSION	2,788,099					
84	DISTRIBUTION						
85	360 (Rights)	3,624	60 years		1.44%	R4	
86	361	19,367	75 years	11%	1.43%	R3	
87	362	448,860	57 years	16%	1.95%	S0.5	
88	362.16	7,648	57 years	16%	1.89%	S0.5	
89	364	607,171	55 years	64%	2.82%	S0.5	
90	365	620,641	44 years	40%	3.07%	R1	
91	366	97,522	70 years		1.35%	R4	
92	367	294,711	46 years	17%	2.41%	R3	
93	368	541,621	44 years	10%	2.42%	L0	
94	369	121,667	59 years	74%	2.81%	R3	
95	370	68,535	15 years	26%	8.06%	L0	
96	370.16 - TX AMI	29,608	15 years	26%	14.29%	L0	
97	370.16 AR EurekaSpringsAMI	7,344	15 years	26%	8.06%	L0	
98	370.16 - LA AMI	182	15 years	26%	8.06%	L0	
99	370.16 - LA AMI Initial	32,172	7 years	26%	14.29%	L0	
100	370.16 Shreveport LA AMI	1,691	7 years	26%	14.29%	L0	
101	370.16 Valley LA AMI	525	7 years	26%	14.29%	L0	
102	371	53,488	25 years	31%	4.9%	L0	
103	373	58,363	40 years	34%	3.13%	L0	
104	TOTAL DISTRIBUTION	3,014,740					
105	GENERAL PLANT						
106	390	222,843	58 years	5%	1.55%	L0	
107	391	9,392	30 years		2.84%	SQ	
108	391 Computer	4	7 years		12.92%	SQ	
109	391 Wind	22	30 years		2.94%	SQ	
110	392	3,875	20 years	(3)%	2.45%	SQ	
111	393	2,391	30 years	2%	2.38%	SQ	
112	394	35,212	35 years	1%	2.24%	SQ	
113	394 - Wind	7	30 years		3.36%	SQ	
114	395	5,007	35 years	2%	1.8%	SQ	
115	396	740	20 years	(2)%	5.1%	SQ	
116	397	119,310	20 years		3.99%	SQ	

117	397.16	14,139	20 years		14.29%	SQ	
118	397.16 AMI	6,463	7 years		14.29%	SQ	
119	398	4,702	20 years		3.56%	SQ	
120	TOTAL GENERAL PLANT	424,107					
121	DEPRECIABLE SUM	11,097,098					

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: DepreciablePlantBase

The depreciable plant base is the November 30, 2024
total company depreciable plant.

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR			Deferred to Account 182.3 (i)	Contra Account (j)
						CURRENTLY CHARGED TO				
						Department (f)	Account No. (g)	Amount (h)		
1	SWEPCO Deloitte Load Analysis		2,049	2,049		Electric	928	2,049		
2	Rate Case Expenses Approved for Recovery in PUCT Final Orders:		1,927,195	1,927,195	(894,250)	Electric	928			
3	Expenses incurred related to SWEPCO's 2017 Fuel Reconciliation Filing - PUCT Docket 47553		1,912	1,912		Electric	928	1,912		
4	Expenses incurred related to Louisiana Public Service Commission Audit of SWEPCO		11,975	11,975		Electric	928	11,975		
5	Expense incurred relate to managin Formula Rates for AEP's WEST Operating Companies and Transco's		284,761	284,761		Electric	928	284,761		
6	Other Miscellaneous expense related to Regulatory and Legislative Actions in the State of Louisiana		36,902	36,902		Electric	928	36,902		
7	2024 Louisiana FRP Filing		234,025	234,025		Electric	928	234,025		
8	2024 SWEPCO Arkansas IRP		625,148	625,148		Electric	928	625,148		
9	2024 SWEPCO RFP Arkansas CPA		16,813	16,813		Electric	928	16,813		
10	Expense incurred relate to Distribution Cost Recovery Factor Filing		8,933	8,933		Electric	928	8,933		

11	Expenses incurred relate to Transmission Cost Recovery Factor Filings and other Regulatory/Legislative Activities relating to Transmission		259,668	259,668		Electric	928	259,668		
12	2024 SWEPCO RFP Louisiana CPA		4,063	4,063		Electric	928	4,063		
13	Labor Accrual 10103		19	19		Electric	928	19		
14	2024 SWEPCO TX DCRF		21,286	21,286		Electric	928	21,286		
15	Miscellaneous Minor Items		186,918	186,918		Electric	928	186,918		
16	Expenses incurred relate to SWEPCO's 2020 Texas Base Rate Case		22,623	22,623		Electric	928	22,623		
17				0						
18	24 SWEPCO AR Formula Rate		363,255	363,255		Electric	928	363,255		
19	SWEPCO AR Storm Reserve App		5,877	5,877		Electric	928	5,877		
20	2019 SWEPCO LA Base Case Filing		63,380	63,380		Electric	928	63,380		
21	24 SWEPCO RFP Arkansas NewGen		9,035	9,035		Electric	928	9,035		
22	24 TXSWEPCO Filing EEPR EECRF		2,536	2,536		Electric	928	2,536		
23	25 SWEPCO AR Base Rate Case		368,349	368,349		Electric	928	368,349		
24	25 SWEPCO TX DCRF		12,430	12,430		Electric	928	12,430		
25	Arkansas 2021 Winter Storm		1,600	1,600		Electric	928	1,600		
26	SWEPCO Louisiana All Bus Units		5,281	5,281		Electric	928	5,281		
27	Louisiana Winter Restoration Costs		240	240		Electric	928	240		
28	Louisiana Winter Storm Fuel Recovery		155	155		Electric	928	155		
29	Maverick Wind Facility		30,106	30,106		Electric	928	30,106		
30	All Companies		435	435		Electric	928	435		
31	Sundance Wind Facility		20,870	20,870		Electric	928	20,870		
32	SWEPCOTX Grid Resiliency App		126,681	126,681		Electric	928	126,681		
33	SWEPCO Louisiana AMI meter deployment		3,742	3,742		Electric	928	3,742		
34	TEXAS OPCOS - ALL BUS UNITS		105	105		Electric	928	105		

35	Pirkey Plant Retirement LPSC		339,001	339,001		Electric	928	339,001		
36	Regulatory Fees	2,574,032		2,574,032		Electric	928	2,574,032		
37	2022 SWEPCO AR Turk Filing		22,431	22,431		Electric	928	22,431		
38	2022 SWEPCO TX Fuel Recncltn		(23,141)	(23,141)		Electric	928	(23,141)		
39	2023 SWEPCO DCRF Filing		(4,400)	(4,400)		Electric	928	(4,400)		
40	2023 SWEPCO LA IRP		188,412	188,412		Electric	928	188,412		
41	2023 SWEPCO TX TCRF Filing		5,672	5,672		Electric	928	5,672		
42	23 ARSWEP Formula Rate Review		29,165	29,165		Electric	928	29,165		
43	23 LASWEP Storm Securitization		517,430	517,430		Electric	928	517,430		
44	23SWEPTX Fuel Surcharge Filing		132,829	132,829		Electric	928	132,829		
45	SWEPCO Texas TCRF 1		26,136	26,136		Electric	928	26,136		
46	EECRF Filing - SWEPCO		31,616	31,616		Electric	928	31,616		
47	TX Fuel Reconciliation Filing		279,263	279,263		Electric	928	279,263		
48	Other Miscellaneous expense related to Regulatory and Legislative Actions in the State of Arkansas		19,362	19,362		Electric	928	19,362		
49	SWEPCO-Wind		4,820	4,820		Electric	928	4,820		
50	Traverse Wind Facility		104,770	104,770		Electric	928	104,770		
51	SWEPCO TX FILING - FUEL RECONC		5,033	5,033		Electric	928	5,033		
52	23 ARSWEPCO AMI Deployment		192,445	192,445		Electric	928	192,445		
53	23 Audit 2021 AR Winter Storm		267,895	267,895		Electric	928	267,895		
54	All Operating Cos All Bus Unit		1,304	1,304		Electric	928	1,304		
55	2020 SWEPCO Texas Fuel Reconciliation		2,086	2,086		Electric		2,086		
56	SWEPCO FERC Audit 2024		302,629	302,629		Electric		302,629		
57	SWEPCO LA Investig Rel Audit		24,043	24,043		Electric		24,043		
58	LPSC Order Capacity Alloc Plan		18,031	18,031		Electric		18,031		
59	SWEPCO Fuel Cost Recovery		15,211	15,211		Electric		15,211		

60	SWEPCO PSA Gen Revisions		87,540	87,540		Electric		87,540		
61	SWEPCO Distribution (non TX)		19	19		Electric		19		
62	Labor Accrual 14021R		124	124		Electric		124		
63	Labor Accrual 10393R		488	488		Electric		488		
64	16 - Various Rate Case Epxenses Pending Future Approval for Collection from State Commission Authorities				10,660,428	Electric			695,771	
46	TOTAL	2,574,032	7,248,581	9,822,613	9,766,178			7,895,418	695,771	

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
Classifications:
- A. Electric R, D and D Performed Internally:
1. Generation
- a. hydroelectric
- i. Recreation fish and wildlife
- ii. Other hydroelectric
- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection
2. Transmission
- a. Overhead
- b. Underground
3. Distribution
4. Regional Transmission and Market Operation
5. Environment (other than equipment)
6. Other (Classify and include items in excess of \$50,000.)
7. Total Cost Incurred
- B. Electric, R, D and D Performed Externally:
1. Research Support to the electrical Research Council or the Electric Power Research Institute
2. Research Support to Edison Electric Institute
3. Research Support to Nuclear Power Groups
4. Research Support to Others (Classify)
5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A. (2) Transmission	RD&D Program Management	3,089		566	3,089	
2		2 Items < \$50,000	59		566	59	
3		EPRI Research Portfolio		218,982	566	218,982	
4	A. (3) Distribution	1 Item < \$50,000	2,690		588	2,690	
5				529,533	506	529,533	
6				84,081	588	84,081	
7	A. (5) Environmental (other than equipment)	Environmental Science & Controls Program Management					
8		2 Items < \$50,000	59,264		506	59,264	
9		IT - EPRI Annual Research Portfolio		34,079	588	34,079	

10		Low Carbon Resource Initiative		59,985	506	59,985	
11	A. (6) Other	2 Items < \$50,000	199		506	199	
12			339		566, 588	339	
13		26 Items < \$50,000		59,950	506	59,950	
14	A. (1) Generation						
15	A. (6)(a) Solar	Solar Field Panel Testing			0.00		
16				34,111	566	34,111	
17				32,645	588	32,645	
18	A. (6)(f) Metering	Advanced Metering Equipment (AMI) Test Bed Development	1,519		588	1,519	
19	B. (4) Research Support to Others	3 Items < \$50,000		1,505	506	1,505	
20	A. (6)(g) Research General	DTC Walnut Test Facility	1,388		566, 588	1,388	
21				1,639	566	1,639	
22	B. (5) Total Cost Incurred Externally			1,639,882		1,639,882	
23		1 Items < \$50,000					
24	A. (7) Total Cost Incurred Internally		133,900			133,900	
25		Total	136,044	1,639,882		1,775,926	
26	(b) Fossil-fuel Steam	Generation Asset Management					
27	B. Electric R&D External	5 Items < \$50,000		2,509	506	2,509	
28	B. Electric R&D External	5 Items < \$50,000		25,044	506, 566, 588	25,044	
29	B. (1) Electric Power Research Institute	EPRI Environmental Controls					
30		EPRI Environmental Science		124,130	506	124,130	
31		EPRI Research Portfolio		104,638	566	104,638	
32		IT - EPRI Annual Research Portfolio		18,083	588	18,084	
33		Low Carbon Resource Initiative		2,320	506	2,320	
34		26 Items < \$50,000		358,068	506, 566, 588	385,068	
35	B. (4) Research Support to Others	3 Items < \$50,000					
36	B. (5) Total Cost Incurred Externally			632,283		632,283	
37		Total	133,900	791,227		766,183	
38				17,272	566	17,272	
39		Program Management					

40		3 Items < \$50,000	64,970		506	64,910	
41				26,697	588	26,697	
42	(e) Unconventional Generation	Center for Energy Advancement Through Technological Membership	385		506	385	
43	B. (1) Electric Power Research Institute	EPRI Environmental Controls		78,973	506	78,973	
44		EPRI Environmental Science		457,921	506	457,921	

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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	29,734,087		
4	Transmission	3,465,693		
5	Regional Market			
6	Distribution	16,745,397		
7	Customer Accounts	3,356,776		
8	Customer Service and Informational	3,456,546		
9	Sales			
10	Administrative and General	2,147,212		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	58,905,711		
12	Maintenance			
13	Production	11,527,936		
14	Transmission	2,127,810		
15	Regional Market			
16	Distribution	20,824,363		
17	Administrative and General	1,577,589		
18	TOTAL Maintenance (Total of lines 13 thru 17)	36,057,698		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	41,262,023		
21	Transmission (Enter Total of lines 4 and 14)	5,593,503		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	37,569,760		
24	Customer Accounts (Transcribe from line 7)	3,356,776		
25	Customer Service and Informational (Transcribe from line 8)	3,456,546		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	3,724,801		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	94,963,409	4,414,943	99,378,352
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	94,963,409	4,414,943	99,378,352
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	48,788,110	2,268,207	51,056,317
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	48,788,110	2,268,207	51,056,317
72	Plant Removal (By Utility Departments)			
73	Electric Plant	10,355,400	481,433	10,836,833
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	10,355,400	481,433	10,836,833
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	151 - Fuel Stock	285,998		285,998
80	152 - Fuel Stock Undistributed	4,157,706		4,157,706
81	154 - Materials and Supplies			
82	163 - Stores Expense Undistributed	4,091,552	(4,091,552)	
83	165 - Other Prepayments			
84	182 - Other Regulatory Assets			
85	183 - Prelim Survey	(28,784)	28,784	
86	184 - Clearing Accounts	3,101,815	(3,101,815)	
87	185 - ODD Temporary Facilities	272,982		272,982
88	186 - Misc Deferred Debits	3,082,545		3,082,545
89	242 - Misc Current & Accrued Liab	9,327		9,327
90	254 - Ohio Reliability			
91	401 - Operation Expense - Nonassociated			
92	402 - Maintenance Exp			
93	421 - Misc Nonoperating Income			
94	426 - Political Activities	166,026		166,026
95	456 - Other Electric Revenue	(1,455)		(1,455)

95	TOTAL Other Accounts	15,137,712	(7,164,583)	7,973,129
96	TOTAL SALARIES AND WAGES	169,244,631		169,244,631

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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	30,717,651	64,357,632	92,489,737	121,946,930
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(15,281,379)	(25,002,312)	(37,042,719)	(42,572,120)
4	Transmission Rights				
5	Ancillary Services	1,067,005	4,081,750	6,135,691	9,287,792
6	Other Items (list separately)				
7	Congestion	21,396,316	45,901,633	62,650,436	83,847,857
8	Operating Reserves	1,066,126	1,619,978	209,867	737,352
9	Transmission Congestion Revenue	(14,981,650)	(49,354,210)	(71,182,934)	(94,826,188)
10	Transmission Losses	2,132,142	3,951,026	5,466,897	8,055,947
46	TOTAL	26,116,211	45,555,497	58,726,975	86,477,570

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	0								
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

<p>(a) Concept: MonthlyPeakLoadExcludingIsoAndRto</p>
<p>Southwestern Electric Power Company's transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.</p>
<p>(b) Concept: OtherService</p>
<p>Southwestern Electric Power Company's transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.</p>

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 2025-11-05	Year/Period of Report End of: 2024/ Q4
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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	16,895,260
3	Steam	12,787,352	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,626,392
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,252,892
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	351,594
7	Other	2,892,924	27	Total Energy Losses	870,219
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	15,680,276	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	23,996,357
10	Purchases (other than for Energy Storage)	8,316,081			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	23,996,357			

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	2,309,787	127,736	4,845	16	9
30	February	1,700,067	79,760	3,523	19	8
31	March	1,737,157	96,550	2,993	19	8
32	April	1,764,498	99,030	3,147	17	17
33	May	2,020,005	115,656	3,728	20	17
34	June	2,372,868	155,076	4,462	24	16
35	July	2,312,083	145,699	4,520	2	17
36	August	2,438,073	119,633	4,593	14	17
37	September	2,018,405	116,381	4,056	20	16
38	October	1,851,079	103,436	3,506	1	17
39	November	1,650,425	65,731	2,840	4	14
40	December	1,821,910	49,662	3,384	12	8
41	Total	23,996,357	1,274,350			

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a term basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: (a) *Dolet Hills (3)	Plant Name: (b) *Flint Creek (1)	Plant Name: (c) *Pirkey (2)	Plant Name: (d) Arsenal Hill	Plant Name: Harry D Mattison	Plant Name: (e) Knox Lee	Plant Name: (f) Lieberman	Plant Name: North Central Wind	Plant Name: (g)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam	Steam	Steam	Gas Turbine	Steam	Steam	Wind	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler	Outdoor Boiler	Outdoor Boiler	No Boiler	Outdoor Boiler	Outdoor Boiler	Wind Generator	Outdoor
3	Year Originally Constructed	1986	1978	1985	1960	2007	1950	1947	2021	
4	Year Last Unit was Installed	1986	1978	1985	2010	2007	1974	1959	2022	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	289.97	279.00	619.34	741.00	349.00	351.00	228.00	808.46	
6	Net Peak Demand on Plant - MW (60 minutes)		274	0	694	371	343	200	761	
7	Plant Hours Connected to Load		7,385	0	6,965	1,113	3,268	2,133	22,279	
8	Net Continuous Plant Capability (Megawatts)		259	0	622	283	335	219		

9	When Not Limited by Condenser Water									
10	When Limited by Condenser Water		259	0	622	283	335	219		
11	Average Number of Employees		82	0	26	6	25	24	6	
12	Net Generation, Exclusive of Plant Use - kWh		1,147,413,000		3,473,917,339	261,492,425	321,399,334	183,902,421	2,637,758,423	2,1
13	Cost of Plant: Land and Land Rights									
14	Structures and Improvements									
15	Equipment Costs									
16	Asset Retirement Costs									
17	Total cost (total 13 thru 20)		404,080,293		476,798,285	131,835,434	69,589,814	45,360,692	1,093,527,402	1,7
18	Cost per KW of Installed Capacity (line 17/5) Including		1,448		643	378	198	199	1,353	
19	Production Expenses: Oper, Supv, & Engr		1,499,387	72,554	3,282,022	96,767	828,075	241,262	1,495,294	2,49
20	Fuel	656,337	27,239,128	3,997,326	84,660,983	15,079,046	12,110,266	6,450,999		
21	Coolants and Water (Nuclear Plants Only)									
22	Steam Expenses		1,108,548		1,141,656		2,282,082	3,245,196	11	
23	Steam From Other Sources									
24	Steam Transferred (Cr)									
25	Electric Expenses		1,327,959	566,944	2,869,366	355,167	7	1,520	2,351,879	
26	Misc Steam (or Nuclear) Power Expenses	662,185	1,048,107	63,683	1,839,816	(12)	373,531	818,841	261,378	
27	Rents		2,627		7,954		736	421		

28	Allowances		(9,468)		(56,001)		(2,918)	(2,965)		
29	Maintenance Supervision and Engineering		492,671	16	123,394	7,324	12,777	8,422	930	
30	Maintenance of Structures	(251)	746,349	33,284	676,253	209,846	650,000	703,405		
31	Maintenance of Boiler (or reactor) Plant	23,597	3,195,861	38,303	8,115,217	4,064	1,928,280	1,895,941		
32	Maintenance of Electric Plant	2,407	1,046,529	43,195	3,164,318	1,297,953	627,004	1,182,567	3,359,331	
33	Maintenance of Misc Steam (or Nuclear) Plant	96,704	1,287,703	(1,734)	959,562	677	55,505	9,751		
34	Total Production Expenses	1,440,979	38,985,401	4,813,571	106,784,540	17,050,832	18,865,345	14,555,360	7,468,823	
35	Expenses per Net kWh		0.0340		0.0307	0.0652	0.0587	0.0791	0.0028	

35	Plant Name	*Dolet Hills (3)	*Dolet Hills (3)	*Dolet Hills (3)	*Flint Creek (1)	*Flint Creek (1)	*Flint Creek (1)	*Pirkey (2)	*Pirkey (2)	*Pirkey (2)	Arsenal Hill	Arsenal Hill
36	Fuel Kind	COMPOSITE	GAS	LIGNITE	COAL	COMPOSIT	OIL	COMPOSITE	GAS	LIGNITE	GAS	OIL
37	Fuel Unit				t		bbl		Mcf	t	Mcf	bbl
38	Quantity (Units) of Fuel Burned				708,279		4,907				25,265,253	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)				8,883		139,999				1,037	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year				33.349		115.945				3.319	
41	Average Cost of Fuel per Unit Burned				35.498		115.945				3.319	
42	Average Cost of Fuel Burned per Million BTU				1.998		19.719				3.201	
43	Average Cost of Fuel Burned per kWh Net Gen				0.022		0.220				0.024	
44	Average BTU per kWh Net Generation				10,991.615	10,991.964	11,146				7,540.983	

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: PlantName

(3) Dolet Hills Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	40.234 %
Central Louisiana Electric Company	50.000 %
Northeast Texas Electric Cooperative	5.860 %
Oklahoma Municipal Power Authority	3.906 %
Total	100.000 %

(b) Concept: PlantName

(1) Flint Creek Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	50 %
Arkansas Electric Cooperative Corporation	50 %
Total	100 %

(c) Concept: PlantName

(2) Pirkey Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	85.936 %
Northeast Texas Electric Cooperative	11.720 %
Oklahoma Municipal Power Authority	2.344 %
Total	100.000 %

(d) Concept: PlantName

Arsenal Hill Unit 6 (J. Lamar Stall Unit), a natural gas-fired combustion turbine combined cycle generating unit, became operational in June 2010. Unit 6 consists of 2 combustion turbines feeding one steam turbine.

(e) Concept: PlantName

Knox Lee Plant - Units 2 and 3 were retired during May 2020 business.

(f) Concept: PlantName

Lieberman Plant - Unit 2 was retired during May 2020 business.

(g) Concept: PlantName

Turk Plant, a 600MW Ultra-supercritical coal unit, became operational in December 2012.

(4) Turk Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	73.33 %
Arkansas Electric Cooperative Corporation	11.67 %
East Texas Electric Cooperative	8.33 %
Oklahoma Municipal Power Authority	6.67 %
Total	100.000 %

In April 2021, SWEPCo acquired a 54.5% ownership share of Sundance wind facility (199 MW total nameplate capacity) which was placed in-service in April 2021.

In September 2021, SWEPCo acquired a 54.5% ownership share of Maverick wind facility (287 MW total nameplate capacity) which was placed in-service in September 2021.

(h) Concept: PlantName

Lone Star Plant was retired during May 2020 business.

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	Net Plant Capability (in megawatts)	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	Cost of Plant	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	

26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	

23	Production Expenses	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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28										
29										
30										
31										
32										
33										
34										
35	TOTAL			0	0	0	0	0	0	0

24									
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31									
32									
33									
34									
35									
36	TOTAL								

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolt by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report :
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; c the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such for the line designated.
- Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if y support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
- Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, gi leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are ac
- Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determ
- Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits (h)	Size of Conductor and Material (i)
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)		(f)	(g)		
1	TL367 Layfield Extension		500.00	500.00	1	0.08	0	1	3-1272 ACSR
2	345 kV in AR	345 kV in AR	0	0		0.00	0	0	
3	TL149 Flint Creek	GRDA GRDA 1 (Interconnect)	345	345	2	3.04	0	1	2x1431.0 ACSR
4	TL149 Flint Creek	CUS Brookline (Interconnect)	345	345	3	17.92	0	1	2156.0 ACSR
5	TL175 Chamber Springs	Clarksville 345	345	345	1	6.85	0	1	2x795.0 ACSR
6	TL288 Chambers Spring	Tontitown	345.00	345.00	1	11.53	0	1	2x795.0 ACSR
7	TL327 Turk (AR)	NW Texarkana	345.00	345.00	2	22.15	0	1	954.0 ACSR
8	TL344 Flint Creek	Shipe Road	345.00	345.00	1	14.40	0	1	2x954.0 ACSR
9	345 kV in LA	345 kV in LA	0.00	0.00		0.00	0	0	
10	TL133 Southwest Shreveport	CLECO Dolet Hills	345.00	345.00	3	34.60	0	1	2156.0 ACSR
11	TL134 Diana	Southwest Shreveport	345.00	345.00	3	3.30	8	1	2156.0 ACSR
12	TL134 Diana	Southwest Shreveport	0.00	0.00		0.00	0	0	2x795.0 ACSR

13	TL134 Longwood	Southwest Shreveport	345.00	345.00	1	19.02	0	1	2x795.0 ACSR
14	TL135 Longwood	Entergy El Dorado	345.00	345.00	2	37.72	0	1	2x1024.0 ACAR
15	TL135 Longwood	Wilkes	345.00	345.00	3	3.06	0.00	1	2x1024.0 ACAR
16	345 kV in OK	345 kV in OK	0.00	0.00		0.00	0.00	0	
17	TL251 Chamber Springs	Clarksville 345	345.00	345.00	1	61.57	0.00	1	2x795.0 ACSR
18	345 kV in TX	345 kV in TX	0.00	0.00		0.00	0.00	0	
19	TL199 Welsh	Monticello	345.00	345.00	3	16.00	0.00	1	2156 ACSR
20	TL199 Welsh	Welsh DC	345.00	345.00	3	0.48	0.00	0	2156.0 ACSR
21	TL270 Lydia	NW Texarkana	345.00	345.00	1	0.14	0.00	1	2156.0 ACSR
22	TL270 Lydia	NW Texarkana	345.00	345.00	3	31.20	0.00	1	2156.0 ACSR
23	TL271 Longwood	Wilkes	345.00	345.00	2	0.23	0.00	1	2x1024.0 ACAR
24	TL271 Longwood	Wilkes	345.00	345.00	3	35.11	0.00	0	2x1024.0 ACAR
25	TL271 Lydia	Valliant	345.00	345.00	1	0.16	0.00	1	2x795 ACSR
26	TL271 Lydia	Valliant	345.00	345.00	3	22.45	0.00	0	2x795 ACSR
27	TL271 Welsh	Wilkes	345.00	345.00	3	30.61	0.00	1	2x795 ACSR
28	TL271 Welsh	Lydia	345.00	345.00	1	0.16	0.00	1	2x795 ACSR
29	TL271 Welsh	Lydia	345.00	345.00	3	23.74	0.00	0	2156.0 ACSR
30	TL272 Diana	Southwest Shreveport	345.00	345.00	3	46.45	0.00	1	2156.0 ACSR
31	TL273 Crockett	Entergy Grimes	345.00	345.00	3	26.40	0.00	1	2x1024.0 ACAR
32	TL273 Crockett	Tenaska Rusk County	345.00	345.00	3	65.61	0.00	1	2x1024.0 ACAR
33	TL273 Crockett	Tenaska Rusk County	345.00	345.00	2	1.53	0.00	1	2x1024.0 ACAR
34	TL273 Diana	Pirkey	345.00	345.00	3	24.70	0.00	1	2x1024.0 ACAR
35	TL273 Lebrock	Tenaska Rusk County	345.00	345.00	3	29.31	0.00	0	2x1024.0 ACAR
36	TL273 Lebrock	Tenaska Rusk County	345.00	345.00	3	8.70	0.00	0	2x1272.0 ACSR
37	TL274 Northwest Texarkana	Welsh	345.00	345.00	3	51.68	12.00	1	2156.0 ACSR
38	TL274 Northwest Texarkana	Welsh	0.00	0.00	2	0.31	0.00	0	2156.0 ACSR
39	TL274 Northwest Texarkana	Welsh	0.00	0.00	1	1.31	0.00	0	2156.0 ACSR
40	TL275 Diana	Welsh Ckt 1	345.00	345.00	3	23.69	0.00	1	2156.0 ACSR

41	TL275 Diana	Welsh Ckt 2	345.00	345.00	3	23.60	0.00	1	2156.0 ACSR
42	TL281 Lebrock	Pirkey	345.00	345.00	1	5.21	0.00	1	2x1272.0 ACSR
43	TL281 Lebrock	Pirkey	0.00	0.00	2	0.90	0.00	0	
44	TL328 Turk (TX)	NW Texarkana	345.00	345.00	2	7.43	0.00	1	954.0 ACSR
45	TL90928 Valliant	NW Texarkana (TX Portion)	345.00	345.00	1	43.48	0.00	1	2-954 ACSR
46	161 kV in AR	161 kV in AR	0.00	0.00		0.00	0.00	0	
47	TL154 VBI	Rogers/Loop Thru Springdale (TLN194:0154G)	161.00	161.00	1	4.40	0.00	1	1590.0 ACSR
48	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	12.70	0.00	1	397.0 ACSR
49	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	6.80	0.00	2	477.0 ACSR & 397.
50	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	13.63	0.00	1	795 ACSR
51	TL172 Siloam Springs	West Siloam Springs (GRDA)	161.00	161.00	1	2.06	0.00	1	1272.0 ACSR
52	TL176 OG&E	Fort Smith - Bonanza - Nort	161.00	161.00	2	13.10	0.00	1	397.0 ACSR
53	TL176 OG&E	Fort Smith - Bonanza - Nort	161.00	161.00	2	0.24	0.00	1	1590.0 ACSR
54	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.63	0.00	2	2x397.0 ACSR
55	TL177 Flint Creek	Dyess Substation	161.00	161.00	2	10.59	0.00	1	2x397.0 ACSR
56	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.46	0.00	1	2156 ACSR
57	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	1.60	0.00	1	1590 ACSR
58	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.63	0.00	2	1020 ACCC
59	TL178 Flint Creek	Siloam Springs Substation	161.00	161.00	1	5.44	0.00	1	2x397.0 ACSR
60	TL178 Flint Creek	Siloam Springs Substation	161.00	161.00	2	1.68	0.00	1	2x397.0 ACSR
61	TL179 Chambers Spring	South Fayetteville	161.00	161.00	1	10.36	0.00	1	2156 ACSR
62	TL179 Chambers Spring	South Fayetteville	0.00	0.00	2	5.70	0.00	0	2x397.0 ACSR
63	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	1	0.22	0.00	1	1272.0 ACSR
64	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	2	2.24	0.00	2	2x397.0 ACSR
65	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	1	3.45	0.00	1	2x397.0 ACSR

66	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	2	7.74	0.00	1	2x397.0 ACSR
67	TL180 Flint Creek	East Centerton	161.00	161.00	1	7.99	0.00	1	1272.0 ACSR
68	TL180 Flint Creek	East Centerton	161.00	161.00	1	1.87	0.00	1	1590.0 ACSR
69	TL180 Flint Creek	East Centerton	161.00	161.00	1	10.40	0.00	1	2156.0 ACSR
70	TL180 Flint Creek	East Centerton	161.00	161.00	1	8.63	0.00	1	1590.0 ACSR
71	TL180 Flint Creek	East Centerton	161.00	161.00	1	0.40	0.00	1	1020 ACCC
72	TL187 SPA	Eureka Springs Double Circu	161.00	161.00	2	1.25	0.00	1	795.0 ACSR
73	TL187 SPA Eur Spr	Eureka Springs Double Circu	161.00	161.00	2	1.25	0.00	1	795.0 ACSR
74	TL188 Eureka Springs	AP&L Interconnection	161.00	161.00	1	0.94	0.00	1	666.0 ACSR
75	TL188 Eureka Springs	AP&L Interconnection	161.00	161.00	2	4.40	0.00	1	666.0 ACSR
76	TL189 Dyess	Beaver Dam	161.00	161.00	1	6.84	0.00	1	2156.0 ACSR
77	TL189 Dyess	Beaver Dam	0.00	0.00	2	30.23	0.00	1	666.0 ACSR
78	TL189 Dyess	Beaver Dam	0.00	0.00	2	11.70	0.00	1	1020.0 ACCC/TW
79	TL189 Dyess	Beaver Dam	0.00	0.00	2	0.66	0.00	2	2156.0 ACSR
80	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	5.50	0.00	1	1272.0 AAC
81	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	0.02	0.00	1	1272.0 ACSR
82	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	2	8.83	0.00	1	2x397.0 ACSR
83	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	0.78	0.00	2	2x397.0 ACSR
84	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	2.11	0.00	1	2x397.0 ACSR
85	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	2.96	0.00	1	2x397.0 ACSR
86	TL282 East Rogers	Rogers	161.00	161.00	1	1.25	0.00	1	1272.0 ACSR
87	TL282 East Rogers	Rogers	161.00	161.00	1	3.92	0.00	1	1590 ACSR
88	TL283 Tontitown	Lowell	161.00	161.00	1	11.59	0.00	1	1590.0 ACSR
89	TL283 Tontitown	Lowell	161.00	161.00	1	0.40	0.00	2	1590.0 ACSR
90	TL283 Tontitown	Lowell	161.00	161.00	1	0.40	0.00	2	2156 ACSR
91	TL285 Siloam Springs	Chambers Spring	161.00	161.00	1	7.56	0.00	1	1590.0 ACSR

92	TL337 North Magazine	Danville (Entergy)	161.00	161.00	1	25.95	0.00	1	1272.0 ACSR
93	TL340 Van Asche	Dyess	161.00	161.00	1	5.97	0.00	1	1590.0 ACSR
94	TL341 Fayetteville	S Fayetteville	161.00	161.00	1	1.98	0.00	1	1590.0 ACSR
95	TL342 Fayetteville	Van Asche	161.00	161.00	1	4.18	0.00	1	1590.0 ACSR
96	TL343 East Centerton	Shipe Road	161.00	161.00	1	6.79	0.00	1	2156 ACSR
97	TL360 Osburn Tap		161.00	161.00	1	1.61	0.00	2	1272.0 ACSR
98	TL389 Greenland	VBI	69.00	161.00	1	40.70	0.00	1	1272 ACSR
99	TL425 Branch	North Magazine	161.00	161.00	2	9.01	0.00	1	250.0 CW
100	138 kV in AR	138 kV in AR	0.00	0.00		0.00	0.00	0	
101	TL159 DeQueen	Craig Junction	138.00	138.00	1	8.21	0.00	1	1272 ACSR
102	TL181 Northwest Texarkana	Patterson	138.00	138.00	2	8.26	0.00	1	1024.0 ACAR
103	TL181 Northwest Texarkana	Patterson (TLN194:00181)	138.00	138.00	1	0.40	0.00	2	1590 ACSR
104	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	1.71	0.00	2	1272.0 ACSR
105	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	23.41	0.00	1	1272.0 ACSR
106	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	0.24	0.00	2	1590 ACSR
107	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	0.07	0.00	1	1590 ACSR
108	TL181 Northwest Texarkana	Patterson (TLN194:00181B)	138.00	138.00	1	0.04	0.00	1	1272 ACSR
109	TL181 Northwest Texarkana	Patterson (TLN194:00181B)	138.00	138.00	2	18.01	0.00	1	4/0 CU
110	TL182 Patterson	Craig Junction	138.00	138.00	1	26.47	0.00	1	1272.0 ACSR
111	TL182 Patterson	Craig Junction	138.00	138.00	2	0.48	0.00	1	1272.0 ACSR
112	TL182 Patterson	Craig Junction	138.00	138.00	1	0.18	0.00	2	1590.0 ACSR
113	TL183 North New Boston	Patterson	138.00	138.00	2	0.10	0.00	1	2x203.2 ACSR
114	TL183 North New Boston	Patterson	138.00	138.00	2	17.09	0.00	1	666.0 ACSR

115	TL184 South Dierks	Patterson	138.00	138.00	1	2.28	0.00	1	2x397.0 ACSR
116	TL184 South Dierks	Patterson	138.00	138.00	2	19.09	0.00	1	2x397.0 ACSR
117	TL184 South Dierks	Patterson	138.00	138.00	2	10.90	0.00	1	397.0 ACSR
118	TL184 South Dierks	Patterson	138.00	138.00	1	0.07	0.00	1	1590 ACSR
119	TL227 Bann	Southeast Texarkana	138.00	138.00	1	0.20	0.00	2	1272.0 ACSR
120	TL227 Bann	Southeast Texarkana	138.00	138.00	1	0.18	0.00	1	1272.0 ACSR
121	TL235 Northwest Texarkana	Northeast Texarkana (Sugarhill)	138.00	138.00	1	0.50	0.00	2	1272.0 ACSR
122	TL280 Mena	Craig Jct.	138.00	138.00	1	28.22	0.00	1	795.0 ACSR
123	TL325 Turk	Sugar Hill	138.00	138.00	1	21.70	0.00	1	1590 ACSR
124	TL330 Turk	Southeast Texarkana	138.00	138.00	1	24.95	0.00	1	1590 ACSR/AW
125	TL330 Turk	Southeast Texarkana	138.00	138.00	1	1.84	0.00	2	1590 ACSR/AW
126	TL330 Turk	Southeast Texarkana	138.00	138.00	1	1.84	0.00	2	T2-397.5 ACSR
127	TL345 Turk	Hope	115.00	138.00	1	1.04	0.00	2	1590 ACSR
128	TL345 Turk	Hope	115.00	138.00	1	5.04	0.00	1	1590 ACSR
129	TL403 Wilkes 138kV Bus Tie		138.00	138.00	1	0.06	0.00	1	2x795 ACSS
130	138 kV in LA	138 kV in LA	0.00	0.00		0.00	0.00	0	
131	TL107 Western Electric Tee	Texas Station	138.00	138.00	1	9.74	0.00	1	1272.0 ACSR
132	TL107 Western Electric Tee	Texas Station	138.00	138.00	1	12.80	0.00	1	795.0 ACSR
133	TL107 Western Electric Tee	Texas Station (TLN194:0107A)	138.00	138.00	1	8.00	0.00	1	1272.0 ACSR
134	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	1	2.27	0.00	1	1272.0 AAC
135	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	2	0.26	0.00	1	1272.0 ACSR
136	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	1	6.80	0.00	1	1703.0 ACAR
137	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	2.72	0.00	1	2156 ACSR
138	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	0.62	0.00	2	2156 ACSR

139	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	0.62	0.00	2	666.6 ACSR
140	TL110 Shreveport 138kV Loop	(TLN194:0110A)	138.00	138.00	1	2.91	0.00	1	1272.0 AAC
141	TL110 Shreveport 138kV Loop	(TLN194:0110A)	138.00	138.00	1	2.12	0.00	0	1272.0 ACSR
142	TL110 Shreveport 138kV Loop	(TLN194:0110B)	138.00	138.00	1	8.90	0.00	1	1272.0 AAC
143	TL110 Shreveport 138kV Loop	(TLN194:0110B)	138.00	138.00	1	1.50	0.00	2	1272.0 AAC & 666.6 ACSR
144	TL110 Shreveport 138kV Loop	(TLN194:0110C)	138.00	138.00	1	2.45	0.00	1	1533.3 ACSR/TW
145	TL112 Center	Logansport	138.00	138.00	1	0.60	0.00	1	755.0 ACAR
146	TL119 Minden Road Tee - Whi	Bodcau - Red Point (TLN194:00119)	138.00	138.00	1	6.86	0.00	1	2x397.0 ACSR
147	TL119 Minden Road Tee - Whi	Bodcau - Red Point (TLN194:0119A)	138.00	138.00	1	4.51	0.00	1	2x397.0 ACSR
148	TL122 Logansport	Rock Hill (LA)	138.00	138.00	2	4.35	0.00	1	755.0 ACAR
149	TL127 Arsenal Hill	Longwood	138.00	138.00	1	15.06	0.00	1	1272 ACSR
150	TL127 Arsenal Hill	Longwood	138.00	138.00	1	1.41	0.00	1	1233.6 ACSR
151	TL127 Arsenal Hill	Longwood	138.00	138.00	3	0.65	0.00	2	1024 ACAR
152	TL127 Marshall - Longwood - Arsenal Hill	Longwood - Lieberman (TLN194:0127A)	138.00	138.00	1	1.83	0.00	1	2156.0 ACSR
153	TL127 Marshall - Longwood - Arsenal Hill	Longwood - Lieberman (TLN194:0127A)	138.00	138.00	2	7.80	0.00	0	2x266.8 ACSR
154	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	0.12	0.00	1	1272 ACSR
155	TL128 Arsenal Hill	Lieberman	138.00	138.00	2	10.93	0.00	1	666.6 ACSR
156	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	1.94	0.00	1	959.6 ACSR/TW
157	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	2.00	0.00	1	666.6 ACSR
158	TL128 Arsenal Hill	Lieberman	138.00	138.00	2	6.43	0.00	1	2-266 ACSR
159	TL128 Arsenal Hill	Lieberman	138.00	138.00	3	0.00	0.00	1	666.6 ACSR

160	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	6.90	0.00	1	1590.0 ACSR
161	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:0129A)	138.00	138.00	1	2.30	0.00	2	2-1590.0 ACSR
162	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	10.78	0.00	1	1272.0 ACSR
163	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	2	0.02	0.00	1	2x397.0 ACSR
164	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	4.25	0.00	1	1926.9 ACSR
165	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:00130)	138.00	138.00	1	0.58	0.00	1	666.0 ACSR
166	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:00130)	138.00	138.00	2	0.98	0.00	0	795.0 ACSR
167	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130A)	138.00	138.00	2	12.22	0.00	1	666.0 ACSR
168	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130B)	138.00	138.00	1	1.28	0.00	1	666.0 ACSR
169	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130B)	138.00	138.00	2	3.06	0.00	0	795.0 ACSR
170	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130C)	138.00	138.00	1	1.40	0.00	1	2x397.0 ACSR
171	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130C)	138.00	138.00	2	4.91	0.00	1	2x397.0 ACSR
172	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130D)	138.00	138.00	1	1.48	0.00	1	2x795.0 ACSR
173	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130D)	138.00	138.00	2	3.40	0.00	1	2x795.0 ACSR
174	TL131 South Shreveport	Frierson (Cleco Interconnection) (TLN194:00131)	138.00	138.00	2	11.18	0.00	1	666.0 ACSR
175	TL131 South Shreveport	Frierson (Cleco Interconnection) (TLN194:0131A)	138.00	138.00	2	6.86	0.00	1	666.0 ACSR
176	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	9.16	0.00	1	2x397.0 ACSR
177	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	2	23.80	0.00	1	2x397.0 ACSR

178	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	0.58	0.00	2	1272 ACSR
179	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	0.04	0.00	1	1590 ACSR
180	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	3	0.80	0.00	1	1272 ACSR
181	TL242 Jefferson Switching S	Lieberman (TLN194:00126)	138.00	138.00	1	0.72	0.00	1	2156.0 ACSR
182	TL242 Jefferson Switching S	Lieberman (TLN194:00126)	138.00	138.00	2	6.48	0.00	0	336.4 ACSR
183	TL292 Finney Tap	Port Robson	138.00	138.00	1	3.25	0.00	1	1590.0 ACSR
184	TL331 Caplis	McDade	138.00	138.00	2	7.87	0.00	0	
185	TL332 Wallace Lake	Finney Tap	138.00	138.00	1	2.63	0.00	2	397.5 ACSR & 1590
186	TL333 Caplis	Port Robson	138.00	138.00	1	1.29	0.00	1	1590.0 ACSR
187	TL333 Caplis	Port Robson	138.00	138.00	1	2.92	0.00	1	1590.0 ACSR
188	TL334 Haughton	McDade	138.00	138.00	2	11.30	0.00	1	4/0 ACSR
189	TL335 Haughton	Red Point	138.00	138.00	2	2.95	0.00	1	1590.0 ACSR
190	TL336 Longwood	Scottsville	138.00	138.00	1	3.88	0.00	1	1590 ACSR
191	TL339 Bean 138kV Loop		138.00	138.00	1	0.72	0.00	2	1590 ACSR
192	TL364 Port Robson	Benteler 1	138.00	138.00	1	4.10	0.00	1	1533 ACSR
193	TL365 Port Robson	Benteler 2	138.00	138.00	1	3.17	0.00	1	1533 ACSR
194	TL374 Ellerbe Road	Lucas	69.00	138.00	1	3.18	0.00	1	1272.0 ACSR
195	TL384 Mount Pleasant New Bos	New Boston	69.00	138.00	1	19.50	0.00	1	1272 ACSR
196	TL428 Flournoy	Pines Road-Hardy St	69.00	138.00	1	4.90	0.00	1	795 ACSR
197	138 kV in OK	138 kV in OK	0.00	0.00		0.00	0.00	0	
198	TL256 Patterson	Craig Junction	138.00	138.00	1	9.41	0.00	1	1272.0 ACSR
199	TL257 DeQueen	Craig Junction	138.00	138.00	1	9.98	0.00	1	1272.0 ACSR
200	TL280 Mena	Craig Junction (TLN194:0280A)	138.00	138.00	1	17.82	0.00	1	2x397.0 ACSR
201	138 kV in TX	138 kV in TX	0.00	0.00		0.00	0.00	0	
202	TL181 Northwest Texarkana	Patterson	138.00	138.00	1	0.19	0.00	1	1024.0 ACAR

203	TL181 Northwest Texarkana	Patterson	138.00	138.00	2	6.55	0.00	0	1272.0 SD
204	TL181 Northwest Texarkana	Patterson	138.00	138.00	3	0.90	0.00	0	2156.0 ACSR
205	TL198 North Mineola	Morton Tap (WCEC)	138.00	138.00	1	7.26	0.00	1	1272.0 ACSR
206	TL198 North Mineola	Morton Tap (WCEC)	138.00	138.00	1	7.26	0.00	2	1272.0&759 ACSR
207	TL200 Center	Carthage Tee	138.00	138.00	1	0.50	0.00	1	795.0 ACSR
208	TL200 Center	Carthage Tee	138.00	138.00	1	1.36	0.00	1	1272 ACSR
209	TL200 Center	Carthage Tee	138.00	138.00	1	17.85	0.00	1	1272 ACSR
210	TL200 Center	Carthage Tee	138.00	138.00	1	10.60	0.00	1	397 ACSR
211	TL204 Center	Logansport	138.00	138.00	1	16.38	0.00	1	755.0 ACAR
212	TL215 Turnertown-Overton-Po	Beckville-Marshall (TLN194:00215E)	138.00	138.00	1	7.22	0.00	1	2x397.0 ACSR
213	TL215 Turnertown-Overton-Po	Beckville-Marshall (TLN194:00215E)	138.00	138.00	2	5.96	0.00	1	2x397.0 ACSR
214	TL218 Mt Pleasant-Pittsburg	Henderson Manufacturing Company (TLN194:0218B)	138.00	138.00	1	9.07	0.00	1	1272.0 ACSR
215	TL220 Lone Star South	Pittsburg	138.00	138.00	1	17.67	0.00	1	1590.0 ACSR
216	TL221 Carthage	Rock Hill	69.00	138.00	1	11.40	0.00	1	1533 ACSR/TW
217	TL227 Bann	Southeast Texarkana	138.00	138.00	1	11.34	0.00	1	1272.0 ACSR
218	TL228 Bann	North New Boston	138.00	138.00	1	1.50	0.00	2	1272.0 ACSR
219	TL228 Bann	North New Boston	138.00	138.00	1	2.20	0.00	1	2x477.0 ACSR
220	TL228 Bann	North New Boston	138.00	138.00	1	14.80	0.00	1	477.0 ACSR
221	TL228 Bann	North New Boston	138.00	138.00	1	0.07	0.00	1	1272.0 ACSR
222	TL228 Bann	North New Boston	138.00	138.00	1	0.04	0.00	1	2156.0 ACSR
223	TL230 Logansport	Rock Hill (TX)	138.00	138.00	1	4.21	0.00	1	1272.0 ACSR
224	TL230 Logansport	Rock Hill (TX)	138.00	138.00	2	17.78	0.00	1	755.0 ACAR
225	TL235 Northwest Texarkana	Northeast Texarkana (Sugarhill)	138.00	138.00	1	10.34	0.00	1	1272.0 ACSR
226	TL236 North Mineola	Perdue	138.00	138.00	2	16.88	0.00	1	2x397.0 ACSR
227	TL236 North Mineola	Perdue	138.00	138.00	1	0.37	0.00	0	1272.0 ACSR
228	TL236 North Mineola	Perdue	138.00	138.00	1	2.13	0.00	0	2x397.0 ACSR

229	TL236 North Mineola	Perdue	138.00	138.00	1	0.36	0.00	1	1272.0 ACSR
230	TL236 North Mineola	Perdue	138.00	138.00	1	1.62	0.00	0	2x397.0 ACSR
231	TL236 North Mineola	Perdue	138.00	138.00	2	10.31	0.00	0	2x397.0 ACSR
232	TL237 Knox Lee	Perdue (TLN194:00237)	138.00	138.00	2	12.87	3.00	1	1272.0 ACSR
233	TL237 Knox Lee	Perdue (TLN194:00237)	0.00	0.00		0.00	0.00	0	2x397.0 ACSR
234	TL237 Knox Lee	Perdue (TLN194:00237A)	138.00	138.00	1	2.76	0.00	1	1272.0 ACSR
235	TL237 Knox Lee	Perdue (TLN194:00237A)	0.00	0.00	2	22.08	0.00	0	2x397.0 ACSR
236	TL237 Knox Lee	Perdue (TLN194:00237A)	0.00	0.00		0.00	0.00	0	397.0 ACSR
237	TL238 Diana	Perdue	138.00	138.00	2	21.85	0.00	1	2x397.0 ACSR
238	TL239 Knox Lee	North Henderson	138.00	138.00	1	7.10	0.00	1	1272.0 ACSR
239	TL239 Knox Lee	North Henderson	138.00	138.00	2	10.78	0.00	0	2x397.0 ACSR
240	TL240 Wilkes Plant	Jefferson Switching Station	138.00	138.00	2	11.10	0.00	1	1024.0 ACAR
241	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241A)	138.00	138.00	1	11.31	0.00	1	1590 ACSR
242	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241B)	138.00	138.00	2	0.20	0.00	1	2156.0 ACSR
243	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241B)	138.00	138.00	1	3.14	0.00	1	1590 ACSR
244	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	1	2.40	0.00	1	795 ACAR
245	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241,C,D)	138.00	138.00	2	5.96	0.00	0	397.0 ACSR
246	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	1	16.80	0.00	1	795 ACSR
247	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	2	0.08	0.00	2	1272.0 ACSR
248	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241E)	138.00	138.00	1	16.60	0.00	1	1590 ACSR
249	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:00241F)	138.00	138.00	1	23.91	0.00	1	2x397.0 ACSR
250	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:00241G)	138.00	138.00	2	13.54	0.00	1	2x1033.5 ACSR

251	TL242 Jefferson Switching S	Lieberman (TLN194:0242A)	138.00	138.00	2	19.80	0.00	1	336.4 ACSR
252	TL242 Jefferson Switching S	Lieberman (TLN194:0242A)	0.00	0.00		0.00	0.00	0	397.0 ACSR
253	TL242 Jefferson Switching S	Lieberman (TLN194:0242)	138.00	138.00	1	1.42	0.00	1	795.0 ACSR
254	TL243 Eastex Switching	Whitney (TLN194:0243C)	138.00	138.00	1	3.27	0.00	1	2x336.0 ACSR
255	TL243 Eastex Switching	Whitney (TLN194:0243B)	138.00	138.00	2	0.83	0.00	0	2x795.0 ACSR
256	TL243 Eastex Switching	Whitney (TLN194:243A1)	138.00	138.00	2	0.83	0.00	0	2x795.0 ACSR
257	TL243 Eastex Switching	Whitney (TLN194:243A1)	138.00	138.00	1	0.30	0.00	0	2x795.0 ACSR
258	TL243 Eastex Switching Stat	South Texas Eastman (TLN194:0243A2)	138.00	138.00	2	0.83	0.00	1	2x795.0 ACSR
259	TL243 Knox Lee	South Texas Eastman (TLN194:0243D)	138.00	138.00	2	6.47	0.00	1	2x336.0 ACSR
260	TL243 Knox Lee	South Texas Eastman (TLN194:0243D)	138.00	138.00	2	0.97	0.00	1	2x795.0 ACSR
261	TL243 Marshall	Pirkey (TLN194:0243E)	138.00	138.00	2	6.53	2.00	1	2x1033.5 ACSR
262	TL243 Pirkey	Whitney (TLN194:0243F)	138.00	138.00	2	15.52	0.00	1	2x1033.5 ACSR
263	TL243 Pirkey	Whitney (TLN194:0243F)	138.00	138.00	2	0.08	0.00	1	2x1272 ACSR
264	TL244 Marshall	Longwood - Arsenal Hill - Longwood - Lieberman	138.00	138.00	1	12.19	0.00	1	1590.0 ACSR
265	TL244 Marshall	Longwood - Arsenal Hill - Longwood - Lieberman	138.00	138.00	1	0.21	0.00	1	1272.0 ACSR
266	TL244 Marshall	Longwood - Arsenal Hill - Longwood - Lieberman	138.00	138.00	2	17.19	0.00	1	2x397.0 ACSR
267	TL244 Marshall	Longwood - Arsenal Hill - Longwood - Lieberman	138.00	138.00	2	0.88	0.00	1	2x477.0 ACSR
268	TL245 Knox Lee	South Shreveport (TLN194:00245)	138.00	138.00	2	11.19	0.00	0	795.0 ACSR
269	TL245 Knox Lee	South Shreveport (TLN194:00245)	138.00	138.00	1	3.76	0.00	0	795.0 ACSR
270	TL245 Rock Hill	Southwest Shreveport	138.00	138.00	2	23.31	0.00	1	397.0 ACSR
271	TL246 North New Boston	Patterson	138.00	138.00	2	5.41	0.00	1	666.0 ACSR

272	TL246 North New Boston	Wilkes	138.00	138.00	2	46.73	0.00	1	666.0 ACSR
273	TL246 North New Boston	Wilkes	138.00	138.00	2	0.15	0.00	1	795.0 ACSR
274	TL246 North New Boston	Wilkes	138.00	138.00	1	0.06	0.00	2	1272.0 ACSR
275	TL247 Wilkes Plant	Jefferson Switching Station	138.00	138.00	1	1.15	0.00	1	1033 ACAR
276	TL247 Wilkes Plant	Jefferson Switching Station	138.00	138.00	1	0.16	0.00	1	1024.0 ACAR
277	TL247 Wilkes Plant	Jefferson Switching Station	0.00	0.00	2	31.68	0.00	0	666.0 ACSR
278	TL248 Lone Star South	Wilkes Plant	138.00	138.00	1	0.12	0.00	1	2x666.0&795.0 ACS
279	TL248 Lone Star South	Wilkes Plant	138.00	138.00	2	10.87	0.00	0	2x795.0 ACSR
280	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	1	0.12	0.00	1	2x336.0&397.0 ACS
281	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	2	12.38	0.00	1	2x666.0&795.0 ACS
282	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	1	0.13	0.00	1	2x397.0 ACSR
283	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00	1	2.42	3.00	1	1272.0 ACSR
284	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00	2	11.86	0.00	0	2x336.0&397.0 ACS
285	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00		0.00	0.00	0	336.4 ACSR
286	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249A)	138.00	138.00	1	3.23	0.00	1	1272.0 ACSR
287	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249C)	138.00	138.00	2	9.76	0.00	0	2x336.0&397.0 ACS
288	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249C)	138.00	138.00		0.00	0.00	0	2x397.0 ACSR
289	TL250 Wilkes Plant	Petty	138.00	138.00	1	0.06	0.00	1	1272 ACSR
290	TL250 Wilkes Plant	Petty	138.00	138.00	1	34.01	0.00	1	2-397 ACSR
291	TL277 Eastex	Harrison Road	138.00	138.00	1	9.57	0.00	1	1272.0 ACSR
292	TL278 Diana-Spring Hill	Lake Lamond (TLN194:00278)	138.00	138.00	1	22.98	0.00	1	1590.0 ACSR
293	TL286 Pittsburg	Winnsboro	138.00	138.00	1	20.32	1.00	1	1590 ACSR
294	TL287 North Mineola	Winnsboro	138.00	138.00	1	25.05	0.00	2	1590 ACSR & 477 ACSR

295	TL287 North Mineola	Winnsboro	138.00	138.00	1	0.07	0.00	1	1590 ACSR
296	TL294 Childress-Shamrock	Gray County Line	138.00	138.00	1	4.92	0.00	1	477.0 ACSR
297	TL294 Childress-Shamrock	Gray County Line	138.00	138.00	2	51.35	0.00	1	477.0 ACSR
298	TL295 Lake Pauline	Russell	138.00	138.00	2	14.22	0.00	1	477.0 ACSR
299	TL300 Lake Pauline	West Childress	138.00	138.00	2	35.14	0.00	1	477.0 ACSR
300	TL384 Mount Pleasant	New Boston	69.00	138.00	1	19.50	0.00	1	1272 ACSR
301	TL392 West Mount Pleasant T		69.00	138.00	1	0.70	0.00	1	1272.0 ACSR
302	TL409 HILL LAKE EXTENSION		138.00	138.00	1	0.25	0.00	2	1272.0 ACSR
303	TL410 Naples Tap		69.00	138.00	1	6.40	0.00	1	1272.0 ACSR
304	TL411 Cookville Tap		69.00	138.00	1	1.93	0.00	1	1272.0 ACSR
305	115 kV in AR		0.00	0.00		0.00	0.00	0	
306	TL171 Okay	AP&L Co Interconnect (TLN194:0171A)	115.00	115.00	2	0.01	0.00	1	1272.0 AAC
307	TL171 Okay	AP&L Co Interconnect (TLN194:0171)	115.00	138.00	1	15.50	0.00	1	1591 ACSR
308	TL171 Okay	AP&L Co Interconnect (TLN194:0171A)	115.00	115.00	2	7.10	0.00	1	1272.0 ACSR
309	TL326 Okay	Patterson	115.00	138.00	1	19.31	0.00	1	1590 ACSR
310	TL326 Okay	Patterson	115.00	138.00	1	0.35	0.00	2	1590 ACSR
311	115 kV in LA	115 kV in LA	0.00	0.00		0.00	0.00	0	
312	TL357 Interconnect	Jeld-Wen	115.00	115.00		0.64	0.00	1	336.4 kCM ACSR
313	115 kV in TX	115 kV in TX	0.00	0.00		0.00	0.00	0	
314	TL296 Shamrock	Gray County Line	115.00	115.00	1	14.24	0.00	1	4/0 ACSR
315	69 kV in AR	69 kV in AR	0.00	0.00		0.00	0.00	0	
316	TL142 Abbott Tee	Waldron	69.00	69.00	1	14.21	0.00	1	477.0 ACSR
317	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151C)	69.00	69.00	2	0.25	0.00	1	397.0 ACSR
318	TL151 Dixie Tee (Disconnected)	Belcher - Texarkana Plant	69.00	69.00	1	0.05	0.00	1	556 ACSR

319	TL151 Dixie Tee (Disconnected)	Belcher - Texarkana Plant	69.00	69.00	2	8.45	0.00	0	
320	TL151 Dixie Tee (Disconnected)	Belcher - Texarkana Plant	69.00	69.00	1	2.28	0.00	1	266.8 ACSR
321	TL151 Dixie Tee (Disconnected)	Belcher - Texarkana Plant	69.00	69.00	2	18.49	0.00	1	4/0 ACSR
322	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152B)	69.00	69.00	1	2.04	0.00	1	2/0 ACSR
323	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152D)	69.00	69.00	2	10.67	0.00	1	4/0 ACSR
324	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152D)	69.00	69.00	1	0.05	0.00	1	556.5 ACSR
325	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	1	2.78	0.00	1	4/0 ACSR
326	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	2	3.77	0.00	1	4/0 ACSR
327	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	1	0.10	0.00	1	556.5 ACSR
328	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	1	5.76	0.00	1	795.0 ACSR
329	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	2	34.47	0.00	1	795 ACSR
330	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	2	1.80	0.00	2	795 ACSR
331	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152A)	69.00	69.00	1	0.13	0.00	1	795 ACSR
332	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152A)	69.00	69.00	2	28.75	0.00	0	
333	TL153 Nashville	Okay	69.00	69.00	2	13.76	0.00	1	559.0 ACAR
334	TL153 Nashville	Okay	69.00	69.00	1	0.37	0.00	1	559.0 ACAR
335	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154B)	69.00	69.00	1	3.07	0.00	1	336.4 ACSR
336	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154B)	69.00	69.00	1	2.46	0.00	1	666.0 ACSR

337	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154D)	69.00	69.00	2	1.99	0.00	1	2x397.0 ACSR
338	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154F)	69.00	69.00	1	0.22	0.00	1	336.4 ACSR
339	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154F)	69.00	69.00	2	3.72	0.00	1	336.4 ACSR
340	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154H)	69.00	69.00	2	2.50	0.00	1	1272 ACSR
341	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	1	1.56	0.00	1	2/0 ACSR
342	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	2	37.36	0.00	1	4/0 ACSR
343	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	1	0.19	0.00	1	795 ACSR
344	TL156 PSO-Midland	State Line (TLN194:00156)	69.00	69.00	1	9.44	0.00	1	2/0 ACSR
345	TL158 Texarkana Plant - Was	12th St - Patterson/tap - Co-Oper Tire (TLN194:0158E)	69.00	69.00	1	2.80	0.00	1	2x336.0 ACSR
346	TL158 Texarkana Plant - Was	12th St - Patterson/tap - Co-Oper Tire (TLN194:0158B)	69.00	69.00	1	0.32	0.00	1	4/0 ACSR
347	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.81	0.00	1	2x397.0 ACSR
348	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.25	0.00	2	1590 ACSR
349	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.30	0.00	1	1272 ACSR
350	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.02	0.00	1	1590 ACSR
351	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	1	1.73	0.00	1	1272.0 ACSR
352	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	1	0.07	0.00	1	795 ACSR

353	TL158 Texarkana Plant-Washi	12th St- Patterson/tap-Co- Oper Tire (TLN194:158A)	69.00	69.00	1	12.50	0.00	1	2x397.0 ACSR
354	TL158 Texarkana Plant-Washi	12th St- Patterson/tap-Co- Oper Tire (TLN194:158A)	69.00	69.00	3	0.65	0.00	1	2x397.0 ACSR
355	TL158 Texarkana Plant-Washi	12th St- Patterson/tap-Co- Oper Tire (TLN194:158A)	69.00	69.00	2	5.25	0.00	1	2x397.0 ACSR
356	TL158 Texarkana Plant-Washi	12th St- Patterson/tap-Co- Oper Tire (TLN194:158D)	69.00	69.00		0.00	0.00	0	1272.0 ACSR
357	TL160 Dierks	South Dierks	69.00	69.00	1	1.25	0.00	1	397.0 ACSR
358	TL160 Dierks	South Dierks	69.00	69.00	2	0.61	0.00	1	397.0 ACSR
359	TL161 Centerton	Rogers (TLN194:0161A)	69.00	69.00	1	9.90	0.00	1	1272.0 AAC
360	TL162 Midland- Huntington-RE	Booneville- Branch/Tap- Magazine-North Magazine (TLN194:0162A)	69.00	69.00	1	2.64	0.00	1	4/0 ACSR
361	TL164 Siloam Springs	Prairie Grove - Greenland (TLN194:0164A)	69.00	69.00	1	1.19	0.00	1	477.0 ACSR
362	TL164 Siloam Springs	Prairie Grove - Greenland (TLN194:0164A)	69.00	69.00	2	19.37	0.00	1	477.0 ACSR
363	TL164 Siloam Springs - Prai	Greenland (TLN194:00164)	69.00	69.00	2	8.04	0.00	1	477.0 ACSR
364	TL164 Siloam Springs - Prai	Greenland (TLN194:00164)	69.00	69.00	2	0.52	0.00	2	477.0 ACSR & 336.4 ACSR
365	TL165 Southeast Texarkana	Texarkana Plant	69.00	69.00	1	0.24	0.00	1	1272.0 ACSR
366	TL167 Mena- Murfreesboro	Dierks (TLN194:0167C)	69.00	69.00	1	2.50	0.00	1	397.0 ACSR
367	TL167 Mena- Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	2	30.50	0.00	1	477.0 ACSR
368	TL167 Mena- Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	1	7.67	0.00	1	477.0 ACSR
369	TL167 Mena- Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	1	0.09	0.00	1	795.0 ACSR
370	TL167 Mena- Murfreesboro	Dierks (TLN194:0167B)	69.00	69.00	1	18.77	0.00	1	266.8 ACSR
371	TL168 Radial Patterson	Nekoosa - Edwards	69.00	138.00	1	5.09	0.00	1	1272.0 ACSR
372	TL169 East Rogers	North Rogers	69.00	69.00	1	1.95	0.00	1	2x397.0 ACSR
373	TL213 Texarkana Plant - Ban	De Kalb - Mt Pleasant/taps (TLN194:0213K)	69.00	69.00	1	0.53	0.00	1	1272.0 ACSR

374	TL213 Texarkana Plant - Ban	De Kalb - Mt Pleasant/taps (TLN194:0213M)	69.00	69.00	1	0.34	0.00	1	1272.0 ACSR
375	TL369 Midland	North Huntington (TLN194:00369)	69.00	161.00	2	4.76	0.00	0	1233.6 ACSR
376	TL370 Midland	Leflore County (State Line) (TLN194:00370)	69.00	161.00	2	7.00	0.00	1	4/0 ACSR
377	TL388 North Huntington	Waldron	69.00	161.00	1	18.53	0.00	1	795 ACSR
378	TL389 Greenland	VBI	69.00	161.00	1	0.04	0.00	1	1272 ACSR
379	69 kV in LA	69 kV in LA	0.00	0.00		0.00	0.00	0	
380	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	0.99	0.00	1	477 ACSR
381	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	26.59	0.00	1	397.0 ACSR
382	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	0.36	0.00	1	556.5 ACSR
383	TL104 Red Point- Dogwood-Bel	Bellevue Oilfield (TLN194:00104)	69.00	69.00	1	8.80	0.00	1	4/0 ACSR
384	TL104 Red Point- Dogwood-Bel	Bellevue Oilfield (TLN194:0104A)	69.00	69.00	1	3.41	0.00	1	4/0 ACSR
385	TL104 Red Point- Dogwood-Bel	Bellevue Oilfield (TLN194:0104B)	69.00	69.00	2	2.17	0.00	1	4/0 ACSR
386	TL108 Logansport	Stanley Tap	69.00	69.00	1	7.00	0.00	1	2/0 ACSR
387	TL108 Logansport	Stanley Tap	69.00	69.00	1	2.67	0.00	1	1/0 ACSR
388	TL111 Dixie Tee (Disconnect	Texarkana Plant (TLN194:00111)	69.00	69.00	2	9.72	0.00	1	266.8 ACSR
389	TL111 Dixie Tee (Disconnect	Texarkana Plant (TLN194:0111A)	69.00	69.00	2	12.00	0.00	1	266.8 ACSR
390	TL112 Center- Powell Street-	Panola Harrsion Rural Electric Association (TLN194:0112B)	69.00	69.00	1	3.88	0.00	1	666.0 ACSR
391	TL112 Center- Powell Street-	Panola Harrsion Rural Electric Association (TLN194:0112B)	69.00	69.00	1	0.54	0.00	1	795 ACSR
392	TL113 Gilliam	Marshall (TLN194:0113B)	69.00	69.00	2	3.57	0.00	1	266.8 ACSR
393	TL113 Gilliam	Marshall (TLN194:0113B)	69.00	69.00	2	6.60	0.00	1	4/0 ACSR
394	TL114 Shreveport 69KV Loop	(TLN194:00114)	69.00	69.00	1	1.77	0.00	1	2x397.0 ACSR

395	TL114 Shreveport 69KV Loop	(TLN194:0114A)	69.00	69.00	1	2.20	0.00	1	1272.0 ACSR
396	TL114 Shreveport 69KV Loop	(TLN194:0114B)	69.00	138.00	1	2.55	0.00	1	1272.0 ACSR
397	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.00	0.00	2	795 ACSR
398	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.33	0.00	1	666.6 ACSR
399	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.00	0.00	2	666.6 ACSR
400	TL114 Shreveport 69KV Loop	(TLN194:0114J)	69.00	69.00	1	0.26	0.00	1	666.6 ACSR
401	TL114 Shreveport 69KV Loop	(TLN194:0114F)	69.00	69.00	1	0.89	1.00	1	666.0 ACSR
402	TL114 Shreveport 69KV Loop	(TLN194:0114G)	69.00	69.00	1	1.81	0.00	1	2x397.5 ACSR
403	TL114 Shreveport 69KV Loop	(TLN194:0114G)	69.00	69.00	1	0.56	0.00	2	666.6 ACSR
404	TL114 Shreveport 69KV Loop	(TLN194:0114H)	69.00	138.00	1	3.02	0.00	1	1233.6 ACSR
405	TL114 Shreveport 69KV Loop	(TLN194:0114K)	69.00	69.00	1	0.15	0.00	1	666.6 ACSR
406	TL114 Shreveport 69KV Loop	(TLN194:0114L)	69.00	69.00	1	1.17	0.00	1	666.0 ACSR
407	TL114 Shreveport 69KV Loop	(TLN194:0114M)	69.00	138.00	1	1.64	0.00	1	1233.6 ACSR
408	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	4	0.60	0.00	1	2500.0 CU
409	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	1	0.50	0.00	1	1272.0 ACSR
410	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	1	1.50	0.00	1	2x397.5 ACSR
411	TL115 Bossier City (AH-Ft H)	(TLN194:0115A)	69.00	69.00	1	1.70	0.00	1	2x397.0 ACSR
412	TL116 North Market- Brownlee	Minden Road (TLN194:00116)	69.00	69.00	1	4.37	0.00	1	666.6 ACSR
413	TL117 Leiberman - Superior	Vivian - Hosston	69.00	69.00	1	6.65	0.00	1	336.4 ACSR

414	TL117 Leiberman - Superior	Vivian - Hosston	69.00	69.00	1	3.80	0.00	1	4/0 ACSR
415	TL118 Ellerbe Road - Finney	Wallace lake (TLN194:0118B)	69.00	69.00	1	5.18	0.00	1	397.5 ACSR
416	TL120 Summer Grove- Flournoy	REA & Bingham Pump Plant (TLN194:0120A)	69.00	69.00	1	6.70	0.00	1	397.0 ACSR
417	TL120 Summer Grove- Flournoy	REA & Bingham Pump Plant (TLN194:0120A)	69.00	69.00	1	2.55	0.00	1	477.0 ACSR
418	TL120 Summer Grove- Flournoy	REA & Bingham Pump Plant (TLN194:0120B)	69.00	69.00	1	9.47	0.00	1	4/0 ACSR
419	TL121 Leiberman- Blanchard	North Market (TLN194:00121)	69.00	69.00	1	6.23	0.00	1	666.6 ACSR
420	TL121 Leiberman- Blanchard	North Market (TLN194:00121)	69.00	69.00	2	0.60	0.00	1	666.6 ACSR
421	TL121 Leiberman- Blanchard	North Market (TLN194:00121)	69.00	69.00	3	0.07	0.00	1	666.6 ACSR
422	TL121 Leiberman- Blanchard	North Market (TLN194:0121A)	69.00	69.00	1	11.75	0.00	1	477.0 ACSR
423	TL121 Leiberman- Blanchard	North Market (TLN194:0121A)	69.00	69.00	1	1.06	0.00	1	959.6 ACSR
424	TL124 Red Point-Calumet- JD	Texaco Oil-Getty Oil (TLN194:00124)	69.00	69.00	1	4.29	0.00	1	266.8 ACSR
425	TL124 Red Point-Calumet- JD	Texaco Oil-Getty Oil (TLN194:0124A)	69.00	69.00	1	4.78	0.00	1	266.8 ACSR
426	TL124 Red Point-Calumet- JD	Texaco Oil-Getty Oil (TLN194:0124B)	69.00	69.00	1	0.37	0.00	1	2/0 ACSR
427	TL125 Flournoy-Pines Road	Hardy St	69.00	69.00	1	5.29	0.00	1	397.5 ACSR
428	TL125 Flournoy-Pines Road	Hardy St	69.00	69.00	2	0.40	0.00	1	397.5 ACSR
429	TL347 E Leesville	Hicks	69.00	69.00	1	16.38	0.00	1	336.4 kCM ACSR
430	TL348 E Leesville	N Leesville	69.00	69.00	1	3.20	0.00	1	336.4 kCM ACSR
431	TL349 Many	Belmont	69.00	69.00	1	3.80	0.00	1	795 kCM ACSR
432	TL349 Many	Belmont	69.00	69.00	2	6.66	0.00	2	795 kCM ACSR
433	TL350 Many	Negreet	69.00	69.00	2	3.97	0.00	1	795 kCM ACSR

434	TL350 Many	Negreet	69.00	69.00	1	8.66	0.00	1	795 kCM ACSR
435	TL351 Noble	Mount Zion	69.00	69.00	1	11.25	0.00	1	795 kCM ACSR
436	TL351 Noble	Mount Zion	69.00	69.00	2	0.87	0.00	1	795 kCM ACSR
437	TL352 Hornbeck	N Leesville	69.00	69.00	1	13.00	0.00	1	336.4 kCM ACSR
438	TL353 Belmont	Marthaville	69.00	69.00	2	1.84	0.00	1	336.4 kCM ACSR
439	TL354 Bayou- Pierre	Kingston	69.00	69.00	1	13.60	0.00	1	336.4 ACSR
440	TL355 Montgomery	Verda	13.80	69.00	1	3.20	0.00	1	336.4 kCM ACSR
441	TL358 Marthaville	Robeline	69.00	69.00	1	8.26	0.00	1	336.4 ACSR
442	TL376 Brooks Street	Edwards Street	69.00	138.00	1	0.85	0.00	1	1233.6 ACSR/TW
443	TL377 Leaside Way	Summer Grove	69.00	69.00	1	1.68	0.00	1	477.0 ACSR
444	TL405 Brownlee Road	North Market	69.00	138.00	1	0.21	0.00	2	1233.6 ACSR
445	TL405 Brownlee Road	North Market	69.00	138.00	1	4.49	0.00	1	1233.6 ACSR
446	TL408 Broadmoor	Fort Humbug	69.00	138.00	1	1.36	1.00	1	1233.6 ACSR/TW
447	69 kV in TX	69 kV in TX	0.00	0.00		0.00	0.00	0	
448	66-027 Clarksville	Greggton w/taps to MidVally	69.00	69.00	1	8.49	0.00	1	2/0 ACSR
449	66-027 Clarksville	& Texoma	0.00	0.00		0.00	0.00	0	755.0 ACAR
450	66-028 Clarksville	Sabine w/tap to Service	69.00	69.00	1	1.85	0.00	1	2/0 ACSR
451	66-028 Clarksville	Pipeline	0.00	0.00	2	7.11	0.00	0	397.0 ACSR
452	66-029 Clarksville	Perdue	69.00	69.00	1	7.29	0.00	1	477.0 ACSR
453	66-030 Clarksville	Perdue	69.00	69.00	1	6.32	0.00	1	2x397.0 ACSR
454	66-030 Clarksville	Perdue	0.00	0.00	2	0.65	0.00	0	
455	66-049 Evenside	Poynter	69.00	69.00	1	3.66	0.00	1	477.0 ACSR
456	66-050 Evenside	Sawmill w/taps to Sohio	69.00	69.00	1	14.89	0.00	1	2/0 ACSR
457	66-050 Evenside	Pump & North Laneville	0.00	0.00		0.00	0.00	0	266.8 ACSR
458	66-056 Flournoy	Woodlawn w/taps to Karnack	69.00	69.00	1	33.22	0.00	1	# 2 CU (7 Strand)

459	66-057 Gilmer	Perdue	69.00	69.00	1	11.44	0.00	1	397.0 ACSR
460	66-058 Gilmer	Pittsburg w/tap to	69.00	69.00	1	24.47	0.00	1	2/0 ACSR
461	66-058 Gilmer	Pittsburg Steel	0.00	0.00		0.00	0.00	0	336.4 ACSR
462	66-059 Grand Saline	Mineola	69.00	69.00	1	6.81	7.00	1	4/0 ACSR
463	66-064 Greggton	Lake Lamond	69.00	69.00	1	2.66	0.00	1	1272 ACSR
464	66-068 Hawkins	Mineola	69.00	69.00	1	1.24	0.00	1	477.0 ACSR
465	66-068 Hawkins	Mineola	0.00	0.00	2	17.42	0.00	1	477.0 ACSR
466	66-069 Hawkins	Perdue	69.00	69.00	1	10.90	0.00	1	477.0 ACSR
467	66-073 Hughes Springs	Linden	69.00	69.00	1	0.25	0.00	1	397.0 ACSR
468	66-073 Hughes Springs	Linden	0.00	0.00	2	15.45	0.00	0	
469	66-077 Kilgore	Overton	69.00	69.00	1	4.72	0.00	1	336.4 ACSR
470	66-077 Kilgore	Overton	0.00	0.00	2	7.70	0.00	0	477.0 ACSR
471	66-078 Kilgore	Sabine	69.00	69.00	1	3.49	1.00	1	4/0 ACSR
472	66-078 Kilgore	Sabine	0.00	0.00	2	2.12	0.00	0	
473	66-080 Knox Lee	Southeast Longview	69.00	69.00	1	5.87	0.00	1	2x477.0 ACSR
474	66-080 Knox Lee	Southeast Longview	0.00	0.00		0.00	0.00	0	2x795.0 ACSR
475	66-081 Lake Lamond	Longview	69.00	69.00	1	3.14	0.00	1	755.0 ACAR
476	66-082 Lake Lamond	Southeast Longview w/tap to	69.00	69.00	1	8.66	0.00	1	2x336.0&397.0 ACS
477	66-082 Lake Lamond	Big Three	0.00	0.00		0.00	0.00	0	397.0 ACSR
478	66-083 Lake Lamond	Longview Heights	69.00	69.00	1	7.16	3.00	1	477.0 ACSR
479	66-083 Lake Lamond	Longview Heights	0.00	0.00		0.00	0.00	0	795.0 ACSR
480	66-088 Longview	Whitney	69.00	69.00	1	2.59	0.00	1	2x336.0 ACSR
481	66-088 Longview	Whitney	0.00	0.00		0.00	0.00	0	2x397.0 ACSR
482	66-094 Marshall	North Marshall	69.00	69.00	2	3.49	0.00	1	1272.0 ACSR
483	66-128 Winfield	Winnsboro w/taps to Mount	69.00	69.00	1	18.69	3.00	1	2/0 ACSR
484	66-128 Winfield	Vernon & Texoma	0.00	0.00	2	12.90	0.00	0	336.4 ACSR
485	66-128 Winfield	Vernon & Texoma	0.00	0.00		0.00	0.00	0	477.0 ACSR

486	66-203 Mount Pleasant	Petty	69.00	69.00	1	2.06	0.00	1	755.0 ACAR
487	66-217 Pittsburg	Winnsboro w/tap to Ferndale	69.00	69.00	1	23.17	1.00	1	266.8 ACSR
488	66-217 Pittsburg	Lake	0.00	0.00		0.00	0.00	0	477.0 ACSR
489	66-330 Carthage	Murvaul REC	69.00	69.00	1	2.62	1.00	1	336.4 ACSR
490	66-330 Carthage	Murvaul REC	0.00	0.00		0.00	0.00	0	397.0 ACSR
491	66-633 Marshall 138	Marshall 69	69.00	69.00	1	0.11	0.00	1	2x1272.0 AAC
492	66-803 (21176) Vernon Main	WFEC Russell (Interconnect)	69.00	69.00	2	4.32	0.00	1	477.0 ACSR
493	66-804 (21200) Shamrock	SPS Magic City	69.00	69.00	1	0.85	0.00	1	2/0 ACSR
494	66-804 (21200) Shamrock	(Interconnect)	0.00	0.00	2	16.92	0.00	0	
495	Plant	Plant	0.00	0.00		0.00	0.00	0	
496	TL118A (Radial) Finney Tap		69.00	69.00	1	0.40	0.00	1	2/0 ACSR
497	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151D)	69.00	69.00	1	1.81	0.00	1	266.8 ACSR
498	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	1	1.40	0.00	1	397.0 ACSR
499	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	1	0.85	0.00	1	556.5 ACSR
500	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	2	11.70	0.00	1	397.0 ACSR
501	TL202 Beckville - Cathage	Center (TLN194:00202)	69.00	69.00	2	6.60	0.00	1	397.0 ACSR
502	TL202 Beckville - Cathage	Center (TLN194:0202A)	69.00	69.00	2	1.55	0.00	1	397.0 ACSR
503	TL202 Beckville - Cathage	Center (TLN194:0202A)	69.00	69.00	1	0.80	0.00	1	397.0 ACSR
504	TL203 Bloomburg	Atlanta	69.00	69.00	2	6.75	0.00	1	397.0 ACSR
505	TL203 Bloomburg	Atlanta	69.00	69.00	1	1.00	0.00	1	397.0 ACSR
506	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205A)	69.00	69.00	1	12.75	0.00	1	1272 ACSR
507	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205B)	69.00	69.00	1	0.03	0.00	1	795 ACSR

508	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205B)	69.00	69.00	2	18.27	0.00	1	267 ACSR
509	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00	1	2.87	0.00	1	2/0 ACSR
510	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00		0.00	0.00	0	336.4 ACSR
511	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00		0.00	0.00	0	4/0 ACSR
512	TL208 Longview Heights	Whitney	69.00	69.00	1	4.18	0.00	1	666.0 ACSR
513	TL208 Longview Heights	Marshall 69	69.00	138.00	1	0.04	0.00	1	1590 ACSR
514	TL209 Daingerfield	Mount Pleasant	69.00	69.00	1	1.44	0.00	1	397.0 ACSR
515	TL209 Daingerfield	Mount Pleasant	0.00	0.00	2	1.30	0.00	1	1272 ACSR
516	TL209 Daingerfield	Mount Pleasant	0.00	0.00	2	14.25	0.00	1	397.0 ACSR
517	TL210 Longview - Whitney	Kilgore - Overton (TLN194:0210A)	69.00	69.00	1	8.94	1.00	1	336.4 ACSR
518	TL210 Longview - Whitney	Kilgore - Overton (TLN194:0210A)	69.00	69.00	2	7.40	0.00	1	336.4 ACSR
519	TL211 Mineola	Gladewater/tap - Pump Stati	69.00	69.00	1	0.24	0.00	1	477.0 ACSR
520	TL212 Mt Pleasant - Mineola	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212G)	69.00	69.00	1	1.55	0.00	1	1272.0 AAC
521	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212A)	69.00	69.00	1	2.29	0.67	1	556.5 ACSR
522	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212F)	69.00	69.00		0.20	0.00	1	477 ACSR
523	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212F)	69.00	69.00		0.60	0.00	1	556 ACSR
524	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212J)	69.00	69.00	1	0.55	0.00	1	477.0 ACSR
525	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:00213)	69.00	69.00	1	8.50	0.00	1	397.0 ACSR

526	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213H)	69.00	69.00	1	0.37	0.00	1	477 ACSR
527	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:00213)	69.00	69.00	1	7.14	0.00	1	1272 ACSR
528	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213E)	69.00	69.00	1	1.07	0.00	1	2/0 ACSR
529	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213G)	69.00	69.00	1	1.30	0.00	1	666.0 ACSR
530	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213M)	69.00	69.00	1	2.70	0.00	1	1272.0 ACSR
531	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213N)	69.00	69.00	1	2.40	0.00	1	2x397.0 ACSR
532	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213K)	69.00	69.00	1	0.54	0.00	1	1272 ACSR
533	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	20.16	0.00	1	336.4 ACSR
534	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	0.05	0.00	1	556 ACSR
535	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	0.35	0.00	1	397.0 ACSR
536	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	4.10	0.00	0	795.0 ACSR
537	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (215)	69.00	69.00	2	16.62	0.00	1	4/0 ACSR
538	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (215)	69.00	69.00	1	6.08	0.00	1	4/0 ACSR
539	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (215)	69.00	69.00	1	0.03	0.00	1	397.0 ACSR
540	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (215A)	69.00	69.00	2	4.10	0.00	1	666.0 ACSR
541	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	1	15.50	0.00	1	1272.0 ACSR
542	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	2	0.50	0.00	1	1272.0 ACSR
543	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	1	0.32	0.00	2	1272.0 ACSR & 2x397 ACSR

544	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215D)	69.00	138.00	1	2.72	0.00	1	1272 ACSR
545	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215D)	69.00	138.00	1	0.63	0.00	2	1272 ACSR
546	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215F)	69.00	69.00	1	6.02	0.00	1	2/0 ACSR
547	TL215 Turnertown- Overton- Poynter	Beckville-Marshall (TLN194:0215F)	69.00	69.00	1	0.00	2.00	1	2/0 ACSR
548	TL216 Hughes Springs	Lone Star Steel (TLN194:00216)	69.00	69.00	1	0.12	0.00	1	1272 ACSR
549	TL216 Hughes Springs	Lone Star Steel (TLN194:0216A)	69.00	69.00	1	8.23	0.00	1	1272 ACSR
550	TL216 Hughes Springs	Lone Star Steel (TLN194:0216B)	69.00	69.00	1	6.88	0.00	1	1272 ACSR
551	TL216 Hughes Springs	Lone Star Steel (TLN194:0216C)	69.00	69.00	1	1.04	1.00	1	397.5 ACSR
552	TL216 Hughes Springs	Lone Star Steel (TLN194:0216C)	69.00	69.00	1	0.80	1.00	2	1590&337 ACSR
553	TL216 Hughes Springs	Lone Star Steel (TLN194:0216D)	69.00	69.00	1	2.21	0.00	1	1272 ACSR
554	TL219 Southeast Longview	Whitney w/tap to Letoureau	69.00	69.00	1	4.35	0.00	1	1024.0 ACAR
555	TL219 Southeast Longview	Whitney w/tap to Letoureau	0.00	0.00		0.00	0.00	0	2/0 ACSR
556	TL219 Southeast Longview	Whitney w/tap to Letoureau	0.00	0.00		0.00	0.00	0	2x795.0 ACSR
557	TL223 Taylor Street	Bann	69.00	69.00	1	9.50	0.00	1	666.0 ACSR
558	TL232 Bloomburg	Texarkana Tap - IPC	69.00	69.00	1	1.85	0.00	1	266.8 ACSR
559	TL290 Daingerfield	Hughes Springs	69.00	69.00	1	6.08	0.00	1	1272 ACSR
560	TL293 Vernon	Red River (Interconnect PSO)	69.00	69.00	1	7.53	0.00	1	556 ACSR
561	TL297 Clarendon	Jericho	69.00	69.00	1	6.22	0.00	1	336.4 ACSR
562	TL297 Clarendon	Jericho	0.00	0.00	1	12.50	0.00	1	477 ACSR
563	TL301 West Childress	Estelline	69.00	69.00	1	17.27	0.00	1	T2 477 ACSR
564	TL301A (Radial) Carey Ext		69.00	69.00	1	0.01	0.00	1	T2 477 ACSR
565	TL302 Vernon Main St	North Vernon	69.00	69.00	1	0.02	0.00	1	477.0 ACSR

566	TL371 Longview Heights	Hallsville	69.00	138.00	1	6.54	0.00	1	954 ACSR	
567	TL372 Hallsville	Marshall	69.00	138.00	1	11.15	0.00	1	954 ACSR	
568	TL373 Evenside	Northwest Henderson	69.00	138.00	1	6.40	0.00	1	1272 ACSR	
569	TL375 Marshall	Rockhill	69.00	138.00	1	2.25	0.00	1	1272.0 ACSR	
570	TL378 Mount Pleasant	West Mount Pleasant	69.00	138.00	1	3.04	0.00	1	1533.3 ACSR	
571	TL379 Blocker Tap		69.00	138.00	1	0.13	0.00	1	397 ACSR	
572	TL381 Clarendon	Memphis	69.00	69.00	1	14.51	0.00	1	T2 477 ACSR	
573	TL382 Memphis	Estelline	69.00	69.00	1	14.20	0.00	1	477 ACSR	
574	TL384 Mount Pleasant	New Boston	69.00	138.00	1	33.30	0.00	1	1272.0 ACSR	
575	TL384 Mount Pleasant	New Boston	69.00	138.00	1	13.50	0.00	1	1233.6 ACSR/TW	
576	TL387 Bann	Thirty Ninth Street	69.00	138.00	1	8.86	0.00	1	1272.0 ACSR	
577	TL390 Pilgrims Pride	Winfield	69.00	138.00	1	8.07	0.00	1	1272.0 ACSR	
578	TL396 Childress Amoco Tap		69.00	69.00	1	1.58	0.00	1	477 ACSR	
579	TL421 Wickes REC Tap	Wickes (SWAEC)	69.00	69.00	1	0.01	0.00	1	795 ACSR	
580	TL422 Quitman	Quitman (WCEC)	69.00	69.00	1	0.18	0.00	1	556 ACSR	
581	TL445 Clarendon (GEC) Ext		69.00	69.00	1	0.02	0.00	1	T2 477 ACSR	
582	Line Costs and expenses are	not available by individual								
583	transmission line.	Total shown in Column j-p								
584					TOTAL	4,034.82	52.67	550		118
36	TOTAL									

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions or
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Right footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	Land and Land Rights
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	TL440 (Radial) Sunshine	Bentonville Substation B	0.02		1	1	1	477	ACSR		161	
2	TL439 Sunshine 161kV Extension		0.20		1	1	1	1,272	54/19		161	877,561
44	TOTAL		0		2	2	2					877,561

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended to function the capacities reported for the individual stations in column (f).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than the name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	ABBOTT - AR	Distribution		34.50	12.47	0.00	3.75	1	
2	ASHDOWN 69/12 - AR	Distribution		69.00	12.47	0.00	21.20	2	
3	BLOOMBURG - AR	Distribution		69.00	12.47		2.00	1	
4	BONANZA - AR	Distribution		34.50	12.47		10.00	4	
5	BONANZA - AR	Transmission		34.50	0.00	0.00	0.00		
6	BONANZA - AR	Distribution		161.00	34.50	0.00	12.00	1	
7	BOONEVILLE - AR	Distribution		69.00	12.47	0.00	12.00	1	
8	BOONEVILLE - AR	Distribution		69.00	12.47		12.00	1	
9	CENTERTON - AR	Distribution		161.00	12.47	0.00	12.00	1	
10	CHAMBERS SPRING - AR	Transmission		345.00	161.00	13.80	405.00	1	
11	DEQUEEN - AR	Transmission		12.00	0.00	0.00	0.00		
12	DEQUEEN - AR	Distribution		69.00	34.50	0.00	7.50	1	
13	DEQUEEN - AR	Transmission		69.00	0.00	0.00	0.00		
14	DEQUEEN - AR	Transmission		69.00	0.00	0.00	0.00		
15	DEQUEEN - AR	Transmission		138.00	70.50	13.09	78.00	1	
16	DEQUEEN - AR	Distribution		69.00	12.47	0.00	40.00	2	
17	DEQUEEN - AR	Transmission		138.00	72.60	11.98	80.00	1	
18	DIERKS - AR	Distribution		69.00	12.47		10.00	1	
19	DIERKS - AR	Distribution		7.62	0.00	0.00	0.00		
20	DIERKS - AR	Distribution		69.00	12.47	0.00	5.60	1	
21	DIXIELAND - AR	Distribution		69.00	12.47	0.00	32.00	2	

22	DIXIELAND - AR	Distribution		161.00	13.09	0.00	25.00	0
23	DYESS - AR	Distribution		69.00	12.47	0.00	15.00	2
24	DYESS - AR	Transmission		161.00	69.00	13.09	624.00	8
25	DYESS - AR	Transmission		161.00	69.00	7.62	80.00	1
26	EAST CENTERTON - AR	Transmission		69.00	0.00	0.00	0.00	
27	EAST CENTERTON - AR	Transmission		69.00	0.00	0.00	0.00	
28	EAST CENTERTON - AR	Transmission		161.00	69.00	12.47	156.00	2
29	EAST ROGERS - AR	Transmission		161.00	69.00	13.90	80.00	1
30	EAST ROGERS - AR	Transmission		161.00	0.00	0.00	0.00	
31	EAST ROGERS - AR	Transmission		69.00	0.00	0.00	0.00	
32	FARMINGTON - AR	Distribution		161.00	12.47	0.00	12.00	1
33	FAYETTEVILLE (SW) - AR	Distribution		12.00	0.00	0.00	0.00	
34	FAYETTEVILLE (SW) - AR	Distribution		161.00	12.47	0.00	48.00	2
35	FLINT CREEK SUB - AR	Transmission		345.00	161.00	13.80	240.00	0
36	FLINT CREEK SUB - AR	Transmission		345.00	161.00	13.80	240.00	1
37	FLINT CREEK SUB - AR	Transmission		345.00	161.00	34.50	405.00	1
38	FOREMAN - AR	Distribution		69.00	12.47	0.00	8.40	2
39	FOREMAN-MAGNOLIA - AR	Distribution		69.00	2.40	0.00	3.75	1
40	GREENLAND - AR	Distribution		69.00	12.47	0.00	15.00	2
41	GREENWOOD - AR	Distribution		34.50	13.20		5.00	1
42	GREGG STREET - AR	Distribution		161.00	12.47	0.00	24.00	1
43	HUNTINGTON - AR	Distribution		69.00	13.09	4.16	7.50	1
44	HUNTINGTON - AR	Distribution		69.00	34.50	0.00	10.10	1
45	HYLAND - AR	Distribution		12.00	0.00	0.00	0.00	
46	HYLAND - AR	Distribution		161.00	12.47	0.00	20.00	1
47	LOWELL (SEP) - AR	Distribution		161.00	12.47	0.00	30.00	2
48	MENA - AR	Transmission		69.00	0.00	0.00	0.00	
49	MENA - AR	Distribution		12.00	0.00	0.00	0.00	
50	MENA - AR	Distribution		69.00	12.47	0.00	26.88	2
51	MENA - AR	Distribution		69.00	34.50	0.00	10.00	1
52	MENA - AR	Transmission		69.00	0.00	0.00	0.00	
53	MENA - AR	Transmission		138.00	72.60	13.80	56.00	1
54	MENA - AR	Transmission		69.00	0.00	0.00	0.00	

55	MIDLAND (SW) - AR	Distribution		69.00	12.47	0.00	7.50	1	
56	NASHVILLE 69KV - AR	Distribution		69.00	36.00	0.00	2.50	1	
57	NASHVILLE 69KV - AR	Transmission		12.47	0.00	0.00	0.00		
58	NASHVILLE 69KV - AR	Transmission		69.00	0.00	0.00	0.00		
59	NASHVILLE 69KV - AR	Distribution		69.00	36.29	0.00	5.00	2	
60	NASHVILLE 69KV - AR	Distribution		69.00	12.47	0.00	7.50	1	
61	NORTH HUNTINGTON - AR	Transmission		161.00	69.00	0.00	50.00	1	
62	NORTH HUNTINGTON - AR	Transmission		69.00	0.00	0.00	0.00		
63	NORTH HUNTINGTON - AR	Transmission		161.00	69.00	12.00	50.00	1	
64	NORTH ROGERS - AR	Distribution		12.00	0.00	0.00	0.00		
65	NORTH ROGERS - AR	Distribution		69.00	12.47	0.00	40.00	2	
66	OKAY - AR	Transmission		138.00	70.50	13.09	54.00	1	
67	OKAY - AR	Distribution		69.00	34.50		5.00	1	
68	OKAY - AR	Distribution		69.00	12.47	0.00	2.00	1	
69	OSBURN - AR	Distribution		161.00	13.09	0.00	24.00	1	
70	OSBURN - AR	Distribution		12.47	0.00	0.00	0.00		
71	PATTERSON - AR	Transmission		138.00	0.00	0.00	0.00		
72	PATTERSON - AR	Transmission		138.00	70.50	13.09	910.00	9	
73	PLEASANT HILL - AR	Distribution		69.00	13.09	0.00	5.00	1	
74	PRAIRIE GROVE - AR	Distribution		69.00	13.09	0.00	15.00	1	
75	REEVES ROAD - AR	Distribution		161.00	13.09	0.00	7.50	1	
76	REEVES ROAD - AR	Distribution		161.00	34.50	0.00	12.00	1	
77	REEVES ROAD - AR	Transmission		161.00	36.20	0.00	12.00	0	
78	REEVES ROAD - AR	Distribution		161.00	13.09	0.00	7.50	0	
79	ROGERS - AR	Distribution		12.00	0.00	0.00	0.00		
80	ROGERS - AR	Distribution		161.00	12.47	0.00	48.00	2	
81	SHIPE ROAD - AR	Transmission		345.00	161.00	13.80	405.00	1	
82	SILOAM SPRINGS 161KV - AR	Transmission		161.00	69.00	13.20	80.00	1	
83	SILOAM SPRINGS 161KV - AR	Transmission		69.00	0.00	0.00	0.00		
84	SOUTH DIERKS - AR	Transmission		138.00	72.60	13.20	50.00	1	
85	SOUTH FAYETTEVILLE - AR	Distribution		161.00	12.47		22.40	1	
86	SOUTH FAYETTEVILLE - AR	Transmission		69.00	0.00	0.00	0.00		
87	SOUTH FAYETTEVILLE - AR	Transmission		161.00	69.00	13.80	80.00	1	
88	SOUTH FAYETTEVILLE - AR	Transmission		69.00	0.00	0.00	0.00		
89	SOUTH FAYETTEVILLE - AR	Distribution		12.00	0.00	0.00	0.00		
90	SOUTH FAYETTEVILLE - AR	Distribution		161.00	12.47	0.00	24.00	1	

91	SOUTH FAYETTEVILLE - AR	Transmission		161.00	69.00	13.09	130.00	0	
92	SOUTH FAYETTEVILLE - AR	Transmission		161.00	0.00	0.00	0.00		
93	SOUTH NASHVILLE - AR	Distribution		138.00	12.47	0.00	24.00	2	
94	SOUTH NASHVILLE - AR	Transmission		69.00	0.00	0.00	0.00		
95	SOUTH SPRINGDALE - AR	Distribution		161.00	12.47		22.40	1	
96	SOUTH SPRINGDALE - AR	Distribution		161.00	12.50	0.00	20.00	1	
97	SOUTHEAST FAYETTEVILLE - AR	Distribution		161.00	12.50	0.00	20.00	1	
98	SOUTHEAST TEXARKANA - AR	Transmission		138.00	72.60	13.20	80.00	1	
99	SPRINGDALE - AR	Distribution		69.00	12.47	0.00	48.00	2	
100	SPRINGDALE - AR	Distribution		12.00	0.00	0.00	0.00		
101	SUGAR HILL (SW) - AR	Transmission		138.00	72.60	12.47	80.00	1	
102	SUGAR HILL (SW) - AR	Distribution		138.00	12.47		12.00	1	
103	TEXARKANA PLANT - AR	Distribution		69.00	12.47	0.00	40.00	2	
104	TONTITOWN - AR	Transmission		345.00	161.00	13.80	675.00	0	
105	TONTITOWN - AR	Transmission		161.00	0.00	0.00	0.00		
106	TONTITOWN - AR	Transmission		345.00	161.00	13.80	405.00	1	
107	TONTITOWN - AR	Transmission		161.00	0.00	0.00	0.00		
108	TURK - AR	Transmission		345.00	138.00	34.50	405.00	1	
109	TURK - AR	Transmission		138.00	115.00	36.20	200.00	0	
110	TURK - AR	Transmission		138.00	115.00	13.20	100.00	1	
111	TWELFTH STREET (SW) - AR	Distribution		69.00	12.47		24.80	2	
112	U.S. MOTORS - AR	Distribution		69.00	4.16	2.40	5.60	1	
113	VAN ASCHE - AR	Transmission		12.47	0.00	0.00	0.00		
114	VAN ASCHE - AR	Distribution		161.00	12.47	0.00	48.00	2	
115	WALDRON - AR	Distribution		69.00	12.47	0.00	7.50	1	
116	WALDRON - AR	Distribution		69.00	13.09	0.00	7.50	1	
117	WEST BOONEVILLE - AR	Transmission		161.00	69.00	11.75	40.00	1	
118	ARSENAL HILL - LA	Transmission		138.00	0.00	0.00	0.00		
119	ARSENAL HILL - LA	Distribution		69.00	12.47	0.00	84.00	2	
120	ARSENAL HILL - LA	Transmission		138.00	70.50	12.47	400.00	2	
121	ARSENAL HILL - LA	Transmission		138.00	0.00	0.00	0.00		
122	ARSENAL HILL - LA	Distribution		12.00	0.00	0.00	0.00		
123	BAYOU PIERRE - LA	Distribution		69.00	13.20	0.00	7.00	1	
124	BEAN - LA	Transmission		12.00	0.00	0.00	0.00		
125	BEAN - LA	Distribution		138.00	12.47	0.00	40.00	1	
126	BELCHER - LA	Distribution		69.00	12.47	0.00	6.25	1	

127	BELLEVUE - LA	Distribution		69.00	12.47	0.00	12.50	1
128	BELLEVUE OIL FIELD - LA	Distribution		69.00	12.47	0.00	5.00	1
129	BELMONT (SEP) - LA	Distribution		69.00	13.20	0.00	14.00	1
130	BLANCHARD - LA	Distribution		69.00	11.95	0.00	41.25	5
131	BLANCHARD - LA	Distribution		69.00	13.09	0.00	15.00	1
132	BODCAU ROAD - LA	Distribution		138.00	12.47	0.00	40.00	2
133	BOSSIER CITY - LA	Distribution		69.00	12.47	0.00	70.00	2
134	BROADMOOR - LA	Distribution		69.00	12.50	0.00	20.00	1
135	BROADMOOR - LA	Distribution		69.00	13.09	0.00	25.00	1
136	BROADMOOR - LA	Transmission		12.00	0.00	0.00	0.00	
137	BROOKS STREET (SW) - LA	Distribution		69.00	12.50	0.00	40.00	2
138	BROOKS STREET (SW) - LA	Transmission		12.00	0.00	0.00	0.00	
139	BROWNLEE - LA	Distribution		69.00	34.50		48.00	4
140	BROWNLEE - LA	Distribution		69.00	34.50	0.00	48.00	4
141	BROWNLEE - LA	Distribution		69.00	12.47	0.00	25.00	2
142	BULLOCK - LA	Distribution		69.00	13.09	0.00	15.00	1
143	CALUMET - LA	Distribution		69.00	12.47	0.00	6.25	1
144	CAMPTI - LA	Distribution		69.00	13.09		10.00	0
145	CANE RIVER (SEP) - LA	Distribution		34.50	13.09		7.50	0
146	CANE RIVER (SEP) - LA	Distribution		34.50	13.09		7.50	0
147	CANE RIVER (SEP) - LA	Distribution		34.50	13.09		7.50	0
148	CANE RIVER (SEP) - LA	Distribution		34.50	13.09		7.50	0
149	CANE RIVER (SEP) - LA	Distribution		115.00	13.20	0.00	28.00	1
150	CAPLIS - LA	Distribution		138.00	12.47		25.00	1
151	CAPLIS - LA	Distribution		138.00	36.20	0.00	30.00	1
152	CAPLIS - LA	Transmission		12.47	0.00	0.00	0.00	
153	CARROLL (SEP) - LA	Distribution		34.50	13.20	0.00	3.50	1
154	CEDAR GROVE (SW) - LA	Transmission		138.00	0.00	0.00	0.00	
155	CRESTON - LA	Distribution		34.50	13.20	0.00	7.00	1
156	DERRY - LA	Distribution		34.50	13.20	0.00	10.50	1
157	DOGWOOD - LA	Distribution		69.00	12.47	0.00	10.50	1
158	DOGWOOD - LA	Distribution		69.00	13.09		7.50	1
159	EDWARDS STREET - LA	Distribution		69.00	12.50	0.00	20.00	1
160	ELLERBE ROAD - LA	Distribution		12.00	0.00	0.00	0.00	
161	ELLERBE ROAD - LA	Distribution		69.00	12.47	0.00	56.00	2
162	FERN STREET - LA	Distribution		12.00	0.00	0.00	0.00	
163	FINNEY - LA	Distribution		69.00	4.36		25.00	4

164	FLOURNOY - LA	Distribution		69.00	12.50	0.00	40.00	2	
165	FLOURNOY - LA	Transmission		138.00	72.60	7.20	80.00	1	
166	FORD - LA	Distribution		69.00	12.47		12.00	1	
167	FORT HUMBUG - LA	Distribution		12.00	0.00	0.00	0.00		
168	FORT HUMBUG - LA	Transmission		12.47	0.00	0.00	0.00		
169	FORT HUMBUG - LA	Transmission		138.00	70.50	13.09	130.00	1	
170	GAHAGAN - LA	Distribution		34.50	13.20	0.00	10.50	1	
171	GENERAL MOTORS - LA	Distribution		138.00	13.80	0.00	90.00	2	
172	GEORGIA PACIFIC (SW) - LA	Distribution		138.00	12.47		7.00	1	
173	GILLIAM - LA	Distribution		69.00	12.47	0.00	5.00	1	
174	GRAND ECOPE - LA	Distribution		34.50	13.20	0.00	14.00	1	
175	GRAVEL POINT - LA	Distribution		69.00	26.40	0.00	14.00	1	
176	HARDY STREET - LA	Distribution		69.00	12.47	0.00	26.50	2	
177	HARTS ISLAND - LA	Distribution		138.00	34.50	0.00	100.00	2	
178	HARTS ISLAND - LA	Distribution		34.50	0.00	0.00	0.00		
179	HAUGHTON - LA	Distribution		138.00	13.09	0.00	25.00	1	
180	HICKS - LA	Distribution		69.00	13.20	0.00	14.00	1	
181	HORNBECK - LA	Distribution		69.00	24.90	0.00	28.00	1	
182	HOSSTON - LA	Distribution		69.00	13.09		10.00	1	
183	KINGSTON - LA	Distribution		69.00	24.90	0.00	28.00	1	
184	KURTHWOOD - LA	Distribution		34.50	13.20	0.00	2.58	1	
185	LAYFIELD 500KV - LA	Transmission		500.00	230.00	13.80	750.00	3	
186	LEASIDE WAY - LA	Transmission		138.00	69.00	13.09	130.00	1	
187	LIEBERMAN - LA	Transmission		138.00	69.00	13.00	50.00	1	
188	LIEBERMAN - LA	Transmission		138.00	69.00	13.20	50.00	2	
189	LIEBERMAN 12KV - LA	Distribution		69.00	12.47	0.00	14.00	2	
190	LINTON ROAD - LA	Distribution		138.00	13.09	0.00	40.00	2	
191	LINWOOD (SW) - LA	Distribution		12.00	0.00	0.00	0.00		
192	LINWOOD (SW) - LA	Distribution		138.00	12.47	0.00	66.00	2	
193	LOGANSPORT - LA	Transmission		138.00	0.00	0.00	0.00		
194	LOGANSPORT - LA	Distribution		69.00	13.09	0.00	12.50	1	
195	LOGANSPORT - LA	Distribution		69.00	12.47	0.00	7.00	1	
196	LOGANSPORT - LA	Transmission		138.00	69.00	13.20	33.30	1	
197	LONGWOOD (SW) - LA	Transmission		13.20	0.00	0.00			
198	LONGWOOD (SW) - LA	Transmission		13.20					
199	LONGWOOD (SW) - LA	Transmission		345.00	138.00	13.80	149.00	1	
200	LONGWOOD (SW) - LA	Transmission		345.00	138.00	12.50	298.00	2	

201	LONGWOOD (SW) - LA	Transmission		13.20	0.00				
202	LUCAS - LA	Distribution		12.00	0.00	0.00	0.00		
203	LUCAS - LA	Distribution		69.00	13.09	0.00	80.00	2	
204	MANSFIELD - LA	Distribution		34.50	13.20	0.00	5.00	1	
205	MANY - LA	Distribution		69.00	13.20	0.00	28.00	1	
206	MARTHAVILLE - LA	Distribution		69.00	13.20	0.00	14.00	1	
207	MARTIN (SW) - LA	Distribution		34.50	12.47		22.50	2	
208	MARTIN (SW) - LA	Distribution		34.50	13.20		22.50	2	
209	MCDADE - LA	Distribution		138.00	12.47	0.00	30.50	2	
210	MCWILLIE STREET - LA	Distribution		12.00	0.00	0.00	0.00		
211	MCWILLIE STREET - LA	Distribution		138.00	12.47	0.00	66.30	2	
212	MIDWAY (SW) - LA	Distribution		69.00	12.47	0.00	94.00	4	
213	MINDEN ROAD - LA	Distribution		69.00	12.47	0.00	40.00	2	
214	MINDEN ROAD - LA	Distribution		12.00	0.00	0.00	0.00		
215	MOTT - LA	Distribution		69.00	24.90	0.00	14.00	1	
216	MOTT - LA	Distribution		26.00	12.00	0.00	5.60	6	
217	NEGREET - LA	Distribution		69.00	24.90	0.00	11.20	1	
218	NOBLE (SEP) - LA	Distribution		69.00	26.40	0.00	25.00	0	
219	NOBLE (SEP) - LA	Distribution		69.00	24.90	0.00	28.00	2	
220	NORTH BENTON (NEW) - LA	Transmission		138.00	70.50	13.09	54.00	1	
221	NORTH LEESVILLE - LA	Distribution		69.00	24.90	0.00	25.00	1	
222	NORTH MARKET - LA	Distribution		69.00	12.50	0.00	40.00	2	
223	OIL CITY - LA	Distribution		69.00	13.20	0.00	5.60	1	
224	PIERREMONT - LA	Distribution		138.00	34.50	0.00	50.00	1	
225	PIERREMONT - LA	Distribution		138.00	12.47	0.00	9.38	1	
226	PIERREMONT - LA	Distribution		12.00	0.00	0.00	0.00		
227	PINES ROAD - LA	Distribution		69.00	12.47	0.00	20.00	1	
228	PINES ROAD - LA	Distribution		69.00	12.50	0.00	20.00	1	
229	PLAIN DEALING - LA	Distribution		69.00	12.47	0.00	10.50	1	
230	PLAIN DEALING - LA	Distribution		69.00	13.09	0.00	9.38	1	
231	PORT ROBSON - LA	Distribution		138.00	12.47	0.00	25.00	1	
232	POWELL STREET - LA	Distribution		12.00	0.00	0.00	0.00		
233	POWELL STREET - LA	Distribution		138.00	12.47	0.00	66.00	2	
234	POWHATAN (SEP) - LA	Distribution		34.50	13.20	0.00	3.13	1	
235	PROVENCAL - LA	Distribution		115.00	13.20	0.00	56.00	2	
236	RAINES - LA	Distribution		12.00	0.00	0.00	0.00		
237	RED OAK (SEP) - LA	Distribution		34.50	13.20	0.00	7.00	1	

238	RED POINT - LA	Transmission		138.00	72.60	13.20	42.00	1	
239	RED POINT - LA	Transmission		138.00	0.00	0.00	0.00		
240	RED POINT - LA	Distribution		138.00	13.09	0.00	25.00	1	
241	RED POINT - LA	Transmission		138.00	66.00	13.80	50.00	1	
242	ROBELINE - LA	Distribution		69.00	13.09	0.00	9.38	1	
243	SHED ROAD - LA	Distribution		69.00	13.09	0.00	10.00	1	
244	SHED ROAD - LA	Distribution		12.00	0.00	0.00	0.00		
245	SHED ROAD - LA	Distribution		69.00	12.47	0.00	14.00	1	
246	SOUTH SHREVEPORT - LA	Distribution		12.00	0.00	0.00	0.00		
247	SOUTH SHREVEPORT - LA	Transmission		138.00	72.60	13.20	166.00	2	
248	SOUTH SHREVEPORT - LA	Distribution		138.00	12.47	0.00	44.80	2	
249	SOUTHWEST SHREVEPORT - LA	Transmission		34.50	0.00	0.00	0.00		
250	SOUTHWEST SHREVEPORT - LA	Transmission		345.00	138.00	34.50	810.00	2	
251	SOUTHWEST SHREVEPORT - LA	Transmission		345.00	138.00	13.80	600.00	0	
252	SUMMER GROVE - LA	Distribution		69.00	12.47	7.20	7.00	1	
253	SUMMER GROVE - LA	Distribution		69.00	12.47	0.00	7.00	1	
254	SUMMER GROVE - LA	Distribution		12.00	0.00	0.00	0.00		
255	SUPERIOR (SW) - LA	Distribution		69.00	12.47	0.00	20.88	2	
256	TRICHEL STREET - LA	Distribution		138.00	13.09	0.00	40.00	1	
257	TRICHEL STREET - LA	Distribution		138.00	12.47	0.00	42.00	1	
258	TRICHEL STREET - LA	Distribution		12.00	0.00	0.00	0.00		
259	VIVIAN - LA	Distribution		69.00	12.47	0.00	18.75	2	
260	WALLACE LAKE - LA	Transmission		138.00	69.00	13.00	83.00	1	
261	WATERWORKS (SW) - LA	Distribution		69.00	12.50	0.00	40.00	2	
262	WATERWORKS (SW) - LA	Distribution		69.00	12.47	0.00	14.00	1	
263	WESTERN ELECTRIC - LA	Distribution		138.00	34.50		144.00	2	
264	WESTERN ELECTRIC - LA	Distribution		12.00	0.00	0.00	0.00		
265	WESTERN ELECTRIC - LA	Distribution		34.50	0.00	0.00	0.00		
266	WESTERN ELECTRIC - LA	Distribution		138.00	12.47	0.00	40.00	2	
267	WHITEHURST - LA	Distribution		138.00	34.50	0.00	73.00	2	
268	WHITEHURST - LA	Transmission		12.00	0.00	0.00	0.00		
269	WHITEHURST - LA	Distribution		138.00	12.47	0.00	20.00	1	
270	AIR PRODUCTS (SW) - TX	Distribution		69.00	12.00	0.00	7.00	1	
271	AIRLINE - TX	Distribution		69.00	12.47	0.00	20.00	1	
272	AIRLINE - TX	Distribution		69.00	12.50	0.00	20.00	1	
273	ALUMAX - TX	Distribution		138.00	13.80	0.00	12.00	1	
274	ATLANTA - TX	Transmission		12.00	0.00	0.00	0.00		

275	ATLANTA - TX	Distribution		69.00	12.47	0.00	66.00	2
276	BALDWIN - TX	Distribution		69.00	13.09		25.00	4
277	BALDWIN - TX	Distribution		69.00	12.00	0.00	5.00	1
278	BANN - TX	Transmission		138.00	70.50	13.09	78.00	1
279	BANN - TX	Transmission		138.00	72.60	12.00	852.00	8
280	BECKVILLE - TX	Distribution		69.00	13.09	0.00	6.25	1
281	BIG SANDY (SW) - TX	Distribution		69.00	13.09	0.00	9.38	1
282	BRYANS MILL - TX	Distribution		138.00	12.47	0.00	9.38	1
283	CAREY - TX	Distribution		69.00	7.20	0.00	1.50	3
284	CARTHAGE - TX	Transmission		12.00	0.00	0.00	0.00	
285	CARTHAGE - TX	Distribution		69.00	12.50	0.00	40.00	2
286	CENTER - TX	Transmission		138.00	0.00	0.00	0.00	
287	CENTER - TX	Distribution		138.00	12.47	0.00	84.00	2
288	CENTER - TX	Transmission		12.00	0.00	0.00	0.00	
289	CHILDRESS AIRPORT PRISON - TX	Distribution		69.00	13.09	0.00	2.49	3
290	CHILDRESS AMOCO - TX	Distribution		69.00	4.16	2.40	7.50	1
291	CHILDRESS WEST (SEP) - TX	Distribution		0.00	0.00	0.00	0.00	
292	CHILDRESS WEST (SEP) - TX	Transmission		7.62	0.00	0.00	0.00	
293	CHILDRESS WEST (SEP) - TX	Transmission		138.00	69.00	12.47	50.00	1
294	CITY LAKE SUB - TX	Distribution		69.00	13.09		30.00	2
295	CLARENDON - TX	Distribution		69.00	7.56	0.00	6.90	3
296	CLARKSVILLE - TX	Transmission		12.00	0.00	0.00	0.00	
297	CLARKSVILLE - TX	Distribution		69.00	12.50	0.00	20.00	1
298	CLARKSVILLE - TX	Distribution		69.00	12.47	0.00	20.00	1
299	COOKVILLE (SW) - TX	Distribution		69.00	12.47	0.00	4.66	1
300	CROCKETT - TX	Transmission		345.00	138.00	13.80	600.00	2
301	DAINGERFIELD - TX	Distribution		69.00	12.47	0.00	42.40	2
302	DEKALB - TX	Distribution		69.00	12.47	0.00	18.75	2
303	DIANA - TX	Transmission		345.00	138.00	13.80	750.00	3
304	DIANA - TX	Transmission		345.00	138.00	13.80		1
305	ESTELLINE - TX	Distribution		69.00	13.09	0.00	2.49	3
306	EVENSIDE - TX	Distribution		69.00	12.50	0.00	40.00	2
307	EVENSIDE - TX	Distribution		12.00	0.00	0.00	0.00	
308	FERNDALE LAKE - TX	Distribution		69.00	12.00	0.00	2.00	1
309	FRIARS SWITCH - TX	Distribution		138.00	12.47	0.00	28.00	2
310	GATES - TX	Distribution		69.00	12.47	0.00	12.00	1

311	GILMER - TX	Distribution		69.00	12.50	0.00	40.00	2	
312	GRAND SALINE - TX	Distribution		69.00	13.09		15.00	2	
313	GREGGTON - TX	Distribution		69.00	12.50	0.00	40.00	2	
314	GREGGTON - TX	Distribution		69.00	12.00	0.00	4.69	1	
315	HALLSVILLE - TX	Distribution		138.00	13.09		95.00	5	
316	HARRISON ROAD - TX	Distribution		138.00	34.50	0.00	133.00	2	
317	HAWKINS - TX	Distribution		69.00	12.47	0.00	25.00	2	
318	HEDLEY - TX	Distribution		69.00	12.50	0.00	2.49	3	
319	HOOKS - TX	Distribution		69.00	12.47	0.00	21.00	2	
320	HOWELL - TX	Distribution		12.00	0.00	0.00	0.00		
321	HOWELL - TX	Distribution		69.00	12.47	0.00	33.00	1	
322	HUGHES SPRINGS - TX	Distribution		69.00	12.47	4.16	21.00	2	
323	IPC 138KV - TX	Distribution		138.00	13.09	0.00	9.38	1	
324	IPC 138KV - TX	Transmission		138.00	0.00	0.00	0.00		
325	IPC-DOMINO - TX	Distribution		138.00	12.47	0.00	7.00	1	
326	IPC-JEFFERSON - TX	Distribution		138.00	12.47	0.00	28.00	2	
327	JEFFERSON - TX	Distribution		69.00	12.47	0.00	9.38	1	
328	JERICO - TX	Transmission		115.00	69.00	8.30	28.00	1	
329	KILGORE - TX	Distribution		69.00	12.50	0.00	20.00	1	
330	KILGORE - TX	Distribution		69.00	12.47	0.00	40.00	2	
331	KILGORE - TX	Distribution		12.00	0.00	0.00	0.00		
332	KINGS HIGHWAY - TX	Distribution		69.00	12.50	0.00	40.00	2	
333	KNOX LEE - TX	Transmission		69.00	0.00	0.00	0.00		
334	KNOX LEE - TX	Transmission		138.00	69.00	12.00	133.00	1	
335	KNOX LEE - TX	Distribution		69.00	13.09	0.00	9.38	1	
336	LAKE LAMOND - TX	Distribution		12.00	0.00	0.00	0.00		
337	LAKE LAMOND - TX	Distribution		69.00	12.47	0.00	60.00	3	
338	LAKE LAMOND - TX	Transmission		138.00	72.60	13.80	80.00	1	
339	LAKE PAULINE (SEP) - TX	Transmission		138.00	69.00	14.40	62.50	1	
340	LAKE PAULINE (SEP) - TX	Distribution		69.00	0.00	0.00	0.00		
341	LETOURNEAU 69/12 - TX	Transmission		69.00	0.00	0.00	0.00		
342	LETOURNEAU 69/12 - TX	Distribution		69.00	12.47	0.00	25.00	1	
343	LEVERETTS CHAPEL - TX	Distribution		138.00	12.47	0.00	9.38	1	
344	LIBERTY CITY - TX	Distribution		138.00	12.47	0.00	11.22	6	
345	LINDEN - TX	Distribution		69.00	12.47	0.00	13.25	2	
346	LONDON (SW) - TX	Distribution		138.00	12.47	0.00	28.00	2	
347	LONE STAR SOUTH - TX	Transmission		138.00	69.00	12.47	133.00	1	

348	LONGVIEW - TX	Distribution		69.00	13.09	0.00	15.00	1	
349	LONGVIEW HEIGHTS - TX	Distribution		12.00	0.00	0.00	0.00		
350	LONGVIEW HEIGHTS - TX	Distribution		138.00	12.47	0.00	40.00	2	
351	LOUISIANA PACIFIC - TX	Distribution		69.00	12.47		24.00	2	
352	MARSHALL 138KV - TX	Transmission		138.00	69.00	13.00	133.00	1	
353	MARSHALL 138KV - TX	Transmission		138.00	69.00	7.20	133.00	1	
354	MARSHALL 69KV - TX	Distribution		12.00	0.00	0.00	0.00		
355	MARSHALL 69KV - TX	Distribution		69.00	13.09		48.00	4	
356	MEMPHIS - TX	Distribution		69.00	13.00	0.00	12.60	3	
357	MEMPHIS - TX	Distribution		69.00	0.00	0.00	0.00		
358	MEMPHIS NW - TX	Distribution		69.00	0.00	0.00	0.00		
359	MID-VALLEY - TX	Distribution		69.00	2.40	0.00	9.38	1	
360	MID-VALLEY LONGVIEW - TX	Distribution		69.00	2.40	0.00	7.00	1	
361	MINEOLA - TX	Transmission		69.00	0.00	0.00	0.00		
362	MINEOLA - TX	Distribution		69.00	13.09	0.00	45.00	2	
363	MINEOLA - TX	Transmission			0.00	0.00	0.00		
364	MONROE CORNERS - TX	Distribution		69.00	12.47	0.00	7.00	1	
365	MOUNT PLEASANT - TX	Distribution		69.00	12.47		11.20	1	
366	MOUNT PLEASANT - TX	Distribution		69.00	13.09		22.40	2	
367	MOUNT VERNON (SW) - TX	Distribution		69.00	12.47	0.00	28.00	2	
368	MOUNT VERNON (SW) - TX	Distribution		12.00	0.00	0.00	0.00		
369	NAPLES - TX	Distribution		69.00	12.47	0.00	11.25	2	
370	NASH - TX	Distribution		138.00	12.47	0.00	50.00	2	
371	NETTLETON - TX	Distribution		69.00	2.40	0.00	2.50	1	
372	NEW BOSTON - TX	Distribution		12.00	0.00	0.00	0.00		
373	NEW BOSTON - TX	Distribution		69.00	12.47	0.00	20.00	1	
374	NEW BOSTON - TX	Distribution		69.00	12.50	0.00	20.00	1	
375	NEW GLADEWATER - TX	Distribution		138.00	12.47	0.00	33.30	1	
376	NEW GLADEWATER - TX	Distribution		12.00	0.00	0.00	0.00		
377	NEW HOPE (SW) - TX	Distribution		69.00	12.47	0.00	18.75	2	
378	NORTH LANEVILLE - TX	Distribution		69.00	34.50		5.00	1	
379	NORTH MARSHALL - TX	Distribution		12.00	0.00	0.00	0.00		
380	NORTH MINEOLA - TX	Transmission		69.00	0.00	0.00	0.00		
381	NORTH MINEOLA - TX	Transmission		138.00	0.00	0.00	0.00		
382	NORTH MINEOLA - TX	Transmission		138.00	0.00	0.00	0.00		

383	NORTH MINEOLA - TX	Transmission		138.00	72.60	7.20	80.00	1	
384	NORTH MINEOLA - TX	Transmission		69.00	0.00	0.00	0.00		
385	NORTH MINEOLA - TX	Distribution		69.00	12.47	0.00	9.38	1	
386	NORTH NEW BOSTON - TX	Transmission		138.00	72.60	13.20	83.00	1	
387	NORTHWEST HENDERSON - TX	Transmission		138.00	69.00	13.20	166.00	2	
388	NORTHWEST TEXARKANA - TX	Transmission		345.00	138.00	13.80	960.00	2	
389	NORTHWEST TEXARKANA - TX	Distribution		13.20	0.00	0.00			
390	OVERTON - TX	Transmission		138.00	0.00	0.00	0.00		
391	OVERTON - TX	Transmission		138.00	0.00	0.00	0.00		
392	OVERTON - TX	Transmission		138.00	72.60	13.20	84.00	2	
393	PERDUE - TX	Transmission		138.00	70.50	13.09	130.00	1	
394	PERDUE - TX	Transmission		138.00	0.00	0.00	0.00		
395	PETTY - TX	Distribution		69.00	13.09		7.50	1	
396	PETTY - TX	Transmission		138.00	70.50	13.09	78.00	1	
397	PETTY - TX	Transmission		138.00	69.00	13.80	133.00	1	
398	PILGRIMS PRIDE - TX	Distribution		69.00	12.47		24.00	2	
399	PIRKEY - TX	Transmission		345.00	138.00	34.50	500.00	1	
400	PIRKEY - TX	Transmission		345.00	138.00	13.80	360.00	1	
401	PITTSBURG (SW) - TX	Transmission		138.00	72.60	7.20	133.00	1	
402	PITTSBURG (SW) - TX	Distribution		69.00	12.50	0.00	40.00	2	
403	PITTSBURG STEEL - TX	Distribution		69.00	12.00		6.25	1	
404	PLILER ROAD - TX	Distribution		138.00	34.50	0.00	60.00	2	
405	POYNTER - TX	Distribution		12.00	0.00	0.00	0.00		
406	POYNTER - TX	Distribution		69.00	12.47	0.00	26.50	2	
407	RED RIVER ARSENAL - TX	Distribution		69.00	12.47	0.00	12.50	1	
408	RICHMOND ROAD - TX	Distribution		69.00	12.47		20.00	1	
409	ROCK HILL - TX	Transmission		138.00	70.50	13.09	180.00	2	
410	ROSBOROUGH - TX	Distribution		69.00	12.47	0.00	2.00	1	
411	SABINE - TX	Distribution		12.00	0.00	0.00	0.00		
412	SABINE - TX	Distribution		69.00	12.47	0.00	20.00	1	
413	SCOTTSVILLE (SW) - TX	Distribution		138.00	13.09	0.00	24.00	2	
414	SERVICE PIPELINE - TX	Distribution		69.00	2.40	0.00	3.13	1	
415	SHAMROCK (SEP) - TX	Transmission		69.00	0.00	0.00	0.00		
416	SHAMROCK (SEP) - TX	Distribution		69.00	13.09	0.00	11.10	3	
417	SHAMROCK (SEP) - TX	Transmission		138.00	69.00	6.10	62.50	1	
418	SHAMROCK (SEP) - TX	Transmission		115.00	69.00	14.40	42.00	1	

419	SKID STATION SW-1003 - D - TX	Distribution		69.00	13.09	0.00	15.00	2
420	SOHIO - TX	Distribution		69.00	2.40	0.00	2.00	1
421	SOUTHEAST LONGVIEW - TX	Distribution		69.00	12.50	0.00	42.00	1
422	SOUTHEAST LONGVIEW - TX	Distribution		69.00	12.47	0.00	41.67	1
423	SOUTHEAST MARSHALL - TX	Distribution		138.00	12.47	0.00	55.40	2
424	SPRINGHILL - TX	Distribution		138.00	12.47	0.00	22.40	1
425	TATUM - TX	Transmission		138.00	12.47	0.00	9.38	1
426	TAYLOR STREET - TX	Distribution		12.00	0.00	0.00	0.00	
427	TAYLOR STREET - TX	Distribution		69.00	12.47	0.00	66.00	2
428	TENAHA - TX	Transmission		138.00	0.00	0.00	0.00	
429	TENAHA - TX	Distribution		138.00	12.47	0.00	9.38	1
430	TEXARKANA OPERATIONS CENTER - TX	Distribution		12.00	0.00	0.00	0.00	
431	TEXARKANA OPERATIONS CENTER - TX	Distribution		69.00	12.50	0.00	20.00	1
432	TEXAS EASTERN - TX	Distribution		69.00	2.30	0.00	7.50	2
433	THIRTY-NINTH STREET - TX	Distribution		12.00	0.00	0.00	0.00	
434	THIRTY-NINTH STREET - TX	Distribution		69.00	12.47	0.00	32.00	2
435	TURNERTOWN - TX	Distribution		69.00	12.47	0.00	9.38	1
436	TURNERTOWN - TX	Distribution		69.00	13.09	0.00	9.38	1
437	WASKOM - TX	Distribution		69.00	13.09	0.00	11.20	1
438	WASKOM - TX	Distribution		69.00	13.09		12.00	1
439	WELLINGTON - TX	Distribution		138.00	7.56	0.00	14.01	3
440	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.00	246.00	1
441	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.00	539.00	2
442	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	0.00	296.00	1
443	WELSH HVDC CONVERTER - TX	Transmission		345.00	0.00	0.00	0.00	
444	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.80	539.00	2
445	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.00	539.00	2
446	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.80	293.00	0
447	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.80	1313.00	5
448	WEST ATLANTA - TX	Transmission		138.00	70.50	13.09	54.00	1
449	WEST MOUNT PLEASANT - TX	Distribution		69.00	12.47	0.00	10.00	1
450	WEST MOUNT PLEASANT - TX	Distribution		12.00	0.00	0.00	0.00	
451	WESTWOOD - TX	Distribution		69.00	13.09	0.00	9.38	1
452	WHITNEY - TX	Distribution		69.00	12.47	0.00	104.00	6
453	WHITNEY - TX	Distribution		69.00	12.47		64.00	4
454	WHITNEY - TX	Transmission		138.00	70.50	13.09	208.00	2

455	WHITNEY - TX	Distribution		12.00	0.00	0.00	0.00		
456	WILKES - TX	Transmission		13.80	0.00	0.00	0.00		
457	WILKES - TX	Transmission		345.00	138.00	13.80	450.00	1	
458	WINFIELD - TX	Distribution		69.00	12.47	0.00	9.37	2	
459	WINNSBORO - TX	Distribution		69.00	12.50	0.00	20.00	1	
460	WINNSBORO - TX	Distribution		69.00	12.00	0.00	20.00	1	
461	WINNSBORO - TX	Transmission		12.47	0.00	0.00	0.00		
462	WINNSBORO - TX	Transmission		138.00	70.50	12.47	130.00	1	
463	WINNSBORO - TX	Transmission		138.00	0.00	0.00	0.00		
464	WOODLAWN (SW) - TX	Distribution		69.00	12.47	0.00	6.25	1	
465	TotalTransmissionSubstationMember								
466	Total								

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Administrative and General Expenses - Maintenance	^(a) AEPSE	935	4,269,595
3	Administrative and General Expenses - Operation	AEPSE	920,921,922,923,924,925,926,928,930.1,930.2,931	7,185,407
4	AEP Transmission	AEPSE	920, 923	1,343,548
5	Central Machine Shop	APCo	107, 108, 500, 512, 513, 531, 553	580,669
6	Chief Commercial Officer	AEPSE	920, 923	901,762
7	Chief Executive Officer	AEPSE	920, 923	11,162,449
8	Chief Financial Officer	AEPSE	920, 923	13,433,454
9	Chief Info & Tech Officer	AEPSE	920, 923	6,339,140
10	Civil & Political Activities and Other Svcs	AEPSE	426.1,426.3,426.4,426.5	665,515
11	Construction Services	AEPSE	107, 108	88,927,221
12	Construction Services	AEP Texas	107, 108	1,333,156
13	Construction Services	PSO	107, 108	1,513,204
14	Current and Accrued Liabilities	PSO	232	2,744,486
15	Current and Accrued Liabilities	AEPSE	901,902,903,904,905	14,132,246
16	Distribution Expenses - Maintenance	AEPSE	590, 591, 592, 593, 594, 597, 598	323,638
17	Distribution Expenses - Maintenance	AEP Texas	592, 593, 594, 595, 596, 597	768,456
18	Distribution Expenses - Maintenance	PSO	592,593,594	1,333,065
19	Distribution Expenses - Operation	AEPSE	580, 581, 582, 583, 584, 586, 587, 588	3,878,908
20	Factored Customer A/R Bad Debts	AEP Credit	426	8,204,434
21	Factored Customer A/R Expense	AEP Credit	426	11,386,511
22	Fleet and Vehicle Charges	AEP Texas	Various	372,297
23	Materials and Supplies	OPCo	107, 163, 184, 570, 571, 572	1,150,227

24	Materials and Supplies	PSO	107, 154, 184, 501, 506, 511, 512, 513, 514, 553, 554, 562, 566, 568, 570, 571, 588, 592, 935	1,857,478
25	Other Power Supply Expenses	AEPSC	556, 557	3,466,575
26	Projects & Services	AEPSC	920, 923	1,411,780
27	Rail Car Lease	I&M	186	1,055,445
28	Rail Car Maintenance	AEGCo	151	4,050,013
29	Research and Other Services	AEPSC	183, 184, 186, 188	664,635
30	Services for Jointly Owned Facility - North Central Wind	PSO	107, 108, 186, 408, 421, 426, 431, 500, 501, 502, 505, 506, 510, 513, 520, 540, 543, 544, 546, 549, 550, 553, 556, 557, 560, 561, 564, 566, 568, 569, 573, 580, 586, 588, 594, 594, 598, 920, 921, 922, 923, 924, 925, 926, 928, 930, 931, 935	43,846,245
31	Steam Power Generation - Maintenance	AEPSC	510, 511, 512, 513, 514	1,744,863
32	Steam Power Generation - Operation	AEPSC	500, 501, 502, 506	12,481,327
33	Transmission Expenses - Maintenance	AEPSC	568, 569, 569.9, 569.2, 569.3, 570, 571, 572, 573	1,056,706
34	Transmission Expenses - Operation	AEPSC	560, 561.2, 561.3, 561.5, 562, 563, 564, 566	13,466,138
35	Utilities	AEPSC	920,923	500,524
36	Fuel & Storeroom Services	AEPSC	151, 152, 163	6,828,381
37	Materials and Supplies	AEP Texas	107,184,566,570,571, 593, 596	1,949,789
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Administrative and General Expenses - Operation	Dolet Hills Lignite Co, LLC	920,921	391,908
22	Building and Property Leases	AEPSE	454	1,476,439
23	Central Maintenance Facility	PSO	107, 108, 186, 512, 513, 549	1,278,447
24	Construction Services	AEP Texas	107,108	286,430
25	Construction Services	APCo	107,108	771,813
26	Construction Services	PSO	107, 108	531,450
27	Distribution Expenses - Maintenance	AEP Texas	592, 593, 594, 595, 596	349,351
28	Distribution Expenses - Maintenance	APCo	593, 594, 595, 596	1,699,417
29	Fleet and Vehicle Charges	AEPSE	Various	593,037
30	Fleet and Vehicle Charges	AEP Texas	Various	359,095
31	HVDC East Transmission Tie	AEP Texas	186, 561, 562, 570, 922, 924, 925	682,052
32	Materials and Supplies	AEP Texas	154	564,793
33	Materials and Supplies	PSO	154	527,623
34	Rail Car Lease	I&M	151	364,632
35	Research and Other Services	I&M	184,186	290,463

36	Transmission Expenses - Operation	OKTCo	560	316,241
42				

Name of Respondent: SWEPCO	This report is: (1) <input type="checkbox"/> An Original (2) <input checked="" type="checkbox"/> A Resubmission	Date of Report: 11/05/2025	Year/Period of Report End of: 2024/ Q4
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FOOTNOTE DATA

(a) Concept: NameOfAssociatedAffiliatedCompany

Affiliated Companies shown in Column (B):
 AEP Credit, Inc. - AEP Credit, Inc.
 AEPSC - American Electric Power Service Corporation
 AEP Texas - AEP Texas, Inc.
 APCo - Appalachian Power Company
 DHLC - Dolet Hills Lignite Company
 I&M - Indiana Michigan Power Company
 OPCo - Ohio Power Company
 PSO - Public Service Company of Oklahoma
 KPCo - Kentucky Power Company
 OHTCo - Ohio Transmission Company

AEPSC Allocations
 Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

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FLEET Allocations (Various)
 Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.